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IN THE

Supreme Court of the United States

OCTOBER TERM, 1987

PACIFIC GAS AND ELECTRIC COMPANY,
a California corporation,
Petitioner,

vs.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA,
Respondent.

APPENDIX TO BRIEF OF RESPONDENTS ULTRAPOWER, INC., AND GWF POWER SYSTEMS COMPANY IN OPPOSITION TO PETITION FOR WRIT OF CERTIORARI

STEVEN C. MCCRACKEN
(*Counsel of Record*)
JOSEPH P. BUSCH, III
JEFFREY T. THOMAS
MICHAEL J. RIDER
ROBERT E. PALMER

GIBSON, DUNN & CRUTCHER
800 Newport Center Drive
Suite 600
Newport Beach, California 92660
(714) 759-3800

Attorneys for Respondents
ULTRAPOWER, INC., and
GWF POWER SYSTEMS COMPANY

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Decision *82 01 103* January 21, 1982

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Rulemaking on the Commission's own motion to establish standards governing the prices, terms, and conditions of electric utility purchases of electric power from cogeneration and small power production facilities.

OIR 2
(Filed September 3, 1980)

(See Appendix A for appearances.)

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OPINION

Summary

This decision orders the major California electric utilities to file standard offers for power purchases based on avoided cost principles. These offers shall be available to all cogeneration and small power facilities that qualify under the Federal Public Utility Regulatory Policies Act of 1978. The decision finds that avoided cost pricing will promote the maximum efficient development of cogeneration and small power resources, diversifying the energy supply in California and reducing the state's oil dependence.

The standard offer gives qualifying facilities (QFs) a series of options to tailor contracts to meet their varied needs.

Within 45 days, the utilities are ordered to file the following standard offer options which will become effective upon a compliance review by the staff. These options are:

- Facilities providing *as-available electricity* (energy delivered without a long-term contract) will receive an as-available energy and an as-available capacity payment in ¢/kWh, varying by time of delivery. The as-available price will be based on a short-run avoided cost methodology, with capacity reflecting an estimate of the utilities' shortage cost (pp. 30-56 [pp. A-30-55]).

- QFs which agree to certain performance standards may receive a *firm capacity* payment, rather than an as-available payment. The firm capacity payment is available in $/kW/year, and may be contracted for and levelized for up to 30 years. The firm capacity payment, like the as-available payment, is based on a shortage cost methodology. Firm capacity contracts will also include payments for energy (pp. 57-64 [pp. A-55-60]).

The decision orders utilities to file within 90 days proposals for three other option which will become available after additional hearings. These options are:

- Energy payments may be fixed in advance for up to five years for QFs which agree to commit to provide energy over the term of the contract. This energy payment may be tied either to an as-available or firm capacity option. Payments will be based on projected variable operating costs of the utilities (p. 51 [p. A-50]).
- A long term contract, based on a utility's long-run resource plan for both energy and capacity shall be available for QFs. This offer will be based on a long-run avoided cost concept (pp. 64-68 [pp. A-60-63]).

The decision also establishes guidelines for the standard offer relating to interconnection costs, refusal to purchases, line losses and other contract terms.

The decision allows utilities to file for review of non-standard contracts with this Commission for two years after the effective date of this decision.

This decision also sets standards for rates for sale of power to QFs. Standby rates currently in effect are found reasonable for all QFs on demand schedules, and will be updated in general rate cases in proportion to increases in per kW capacity costs. They are eliminated for QFs who achieve an 85% on-peak capacity factor. Alternate standby rates are adopted for QFs on time-of-use rates. A time frame for planning periods of scheduled maintenance is adopted and scheduled maintenance rates are set at regular tariff rates. Added demand charges are waived for maintenance fitting utility schedules. Interruptible service offerings are made available for all large QFs.

I. Introduction

California has a longstanding demonstrated interest in promoting cogeneration and small power production, as

shown by various actions by this Commission and by the California Legislature (see, e.g., Public Utilities (PU) Code Sections 2801-2824). Cogeneration facilities simultaneously produce two forms of useful energy, such as electric power and steam. Cogeneration facilities use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. Small power production facilities use biomass, geothermal energy, waste or renewable resources, including wind, the sun, and water, to produce electric power. Reliance on these sources of energy can reduce the need to consume traditional fossil fuels to generate electric power.

In Decision (D.) 91109 in Order Instituting Investigation (OII) 26 we recited the following reasons for promoting the development of such alternate resources:

a. Cogeneration uses fuels more efficiently than when industrial processes and electric generation are performed separately.

b. Alternate generating sources diversify the utility's resource plan and minimize dependence on any single source of generation.

c. Generation from biomass, wood waste, and refuse offers independence from foreign fuel sources. The use of domestic fuels is important for reasons of international economics and politics.

d. The development of many small power plants contributes to system reliability. The probability of many small plants failing simultaneously is less than the probability of one large central station plant suffering a forced outage.

e. The lead time required for construction of a small facility is estimated to be several years less than for large central station power plants. Permitting and siting are considerably

simplified due to the small size and location at an existing industrial facility.

f. The utility in many cases will not have to raise the capital to construct the facility, and the facility will not be included in the utility's rate base.

In D.91109, December 19, 1979, we adopted "avoided cost" as the reasonable basis for payment by a utility to purchase power from such facilities.

Meanwhile, cogeneration and small power production have also been the subject of federal actions intended to promote their development, particularly Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). Each electric utility is required under Section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which are defined as qualifying facilities under Section 201. For such purchases electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210 further requires the Federal Energy Regulatory Commission (FERC) to prescribe rules as FERC determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from and sell electric power to cogeneration and small power production facilities.

On February 19, 1980, FERC issued its final rules implementing Section 210. (Docket No. RM79-55, Order No. 69 (45 Fed Reg 12214).) These regulations require that electric utilities purchase electric energy and capacity from qualifying cogenerators and small power producers at a rate equal to the utility's avoided cost of generating the power itself or purchasing it elsewhere. The criteria and procedure by which cogenerators and small power producers obtain qualifying status are set forth in the FEC

rules issued under Section 201. (Docket No. RM79-54, Order No. 70, March 13, 1980 (45 Fed Reg 17959).)

The implementation of the Section 210 rules is reserved to state regulatory authorities. Within one year of the issuance of the rules, each state regulatory agency is required to commence implementation, by way of:

> ". . . the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under. . .(the rules), or any other action designed to implement. . . (the rules)."

Within one year each state regulatory authority is required to file with FERC a report describing the manner in which it will implement the rules.

By Order Instituting Rulemaking (OIR) 2 dated September 3, 1980, this Commission initiated this proceeding for the purpose of establishing standards governing the prices, terms, and conditions of electric utility purchases of electric power from qualifying cogeneration and small power production facilities, under the FERC rules. The order and the "Preliminary Draft Staff Report on Cogeneration and Small Power Production Pricing Standards" were served simultaneously on respondents and interested parties. The original schedule contemplated written comments addressing the staff report to be filed by September 29, 1980, the final staff report, and a public hearing on November 3, 1980, for "oral comments on issues pertinent to this proceeding." By Administrative Law Judge's (ALJ) Ruling dated September 18, 1980, the time for filing written comments was extended to October 15, 1980, and the public hearing postponed until December 2, 1980. By a second ALJ's Ruling dated November 21, 1980, the public hearing was postponed until February 3, 1981, so that staff would have sufficient opportunity to assimilate the numerous and substantial comments in preparing its final report. The hearing dates set for December remained on calendar and

parties appeared to offer further comments and to argue several pending motions. At the December hearing, staff moved for an interim order addressing the ultimate applicability of this decision to contracts signed during the pendency of this proceeding. Staff's motion was the subject of D.93054 dated May 18, 1981, and D.93393 dated August 4, 1981, which provide sellers an option to amend contracts to conform with the provisions of this decision.

The final staff report was issued on January 20, 1981. Public hearings to receive comments on the final staff report were held February 3, 4, and 5, 1981.

II. Procedural Matters

The designation of this proceeding indicates that this is one of the first matters conducted under our rulemaking procedures adopted June 17, 1980. The unfamiliarity of the procedure has apparently contributed to a concern that factual issues will be decided without the opportunity for evidentiary hearings. Southern California Edison Company (Edison), San Diego Gas & Electric Company (SDG&E), and Mass Production Systems (MPS) each filed a written motion asking for evidentiary hearings.

Edison argues that a prehearing conference is necessary to identify unresolved issues that in turn are necessarily resolved in an evidentiary hearing. It contends that an inadequate factual basis for this decision denies due process of law to affected parties.

In support of its position, Edison cites FERC rule Section 292.401(a) which provides for implementation of the rules "after notice and an opportunity for public hearing." It asserts that the hearing allowed in this matter is insufficient for FERC purposes. It also states that the staff report does not have an adequate factual basis upon which to establish the proposed standards. It argues that only an evidentiary hearing will allow this Commission to "establish standards which will equitably balance those vary-

ing interests which it is the responsibility of the Commission to protect."

SDG&E also requests a prehearing conference which it contends is required for the following reasons:

1. To expand the scope of the proceeding to permit an evidentiary hearing for the purpose of reviewing standard form contracts.

2. To determine the need for an evidentiary hearing on existing issues.

3. to place limitations on the proceeding.

4. To resolve certain procedural problems.

In its brief SDG&E observes some change in the staff position but argues that staff's proposal still unnecessarily limits subsequent evidentiary hearings.

MPS argues that the commission should provide for evidentiary hearings (within the scope of OII 26) to investigate and adopt standards to ensure system safety and reliability of interconnected operations. It contends such standards are necessary to the development of safe, economical cogeneration and small power production hardware, leading in turn to qualifying facilities that rely on such hardware.

Staff replied initially that it would consider such motions in the nature of comments in preparing its final report. Various other parties support one or more of the motions.

Staff in its final report argues that this procedure satisfies the "public hearing" requirement imposed by FERC. It states that FERC rules specifically authorize state agencies to implement rules by issuing regulations or taking other action reasonably designed to implement the rules. The rulemaking procedure, staff further argues, is an appropriate means for the consideration and adoption of standards and guidelines governing the utilities' purchases

from qualifying facilities. Although staff recommends evidentiary hearings to review the offers which the utilities will make in compliance with such standards and guidelines, staff believes that any evidentiary hearings which might have been instituted before the establishment of these standards and guidelines would have been premature, time-consuming, and ultimately inconclusive.

We agree with staff that the rulemaking procedure is an appropriate way to decide generic policy questions such as the issues we resolve in this decision. We also agree with the substance of the three motions that certain issues will require resolution in an evidentiary proceeding. In the following discussion, we provide for later evidentiary hearings that will address the primary concerns of the moving parties. Because the evidentiary proceeding we provide is not identical to any of the moving parties' proposals, however, we deny each of the motions for procedural purposes.

III. Applicability

This proceeding has been initiated to further implement our decision in D.91109, to respond to FERC rules, to discharge our responsibilities under Public Utilities Code §2821. To avoid confusion, we use the terminology and structure of the FERC rules throughout this decision. A number of parties to this proceeding have raised questions about the applicability of these rules either to certain California utilities, or to particular entities which are interested in contracting with utilities. We address these questions in this section.

The staff raised the issue of the applicability of these standards in cases where utilities have an equity interest in a facility. One criterion describing a qualifying facility is a limit of utility equity ownership to no more than 50%. In its final report staff analyzes applicable statutes and rules relating to utility ownership and offers the following summary:

"The approach suggested by FERC is as follows: Given state regulatory authority over retail sales, the Commission may prohibit the parent utility from passing on to its ratepayers all of the expenses paid to its subsidiary. In return the Commission would allow the utility subsidiary to earn a higher rate of return than the parent. Accordingly, the parent utility would only be entitled to recover through rates its purchases based on cost of service rather than avoided cost. This approach recognizes that ratepayers should derive some benefit from incurring the additional risk created by the utility subsidiary in potentially affecting capital ratios of the parent without limiting the amount of expenses recoverable by the parent. There appears to be little incentive for the utility to negotiate prices at other than the parent's avoided cost if its subsidiary could enjoy high profits, subsidized by the ratepayers of the parent."

"The FERC's approach thus equitably balances the risks and benefits faced by the parent and its subsidiary. In the event of project failure, the subsidiary could not recover its costs through amortization. Such costs would be borne by the subsidiary's stockholders. The parent, in turn, would make no avoided cost payment to the subsidiary, having received no power. In the case of project success, however, the unregulated subsidiary could retain all profits and earn a greater rate of return than its parent. . .

"Review of purchased power costs incurred by the parent utility from its subsidiary should be made in ECAC proceedings. Capital expenses incurred by the utility should be reviewed in general rate proceedings."

The resulting staff recommendation is that the Commission should consider limiting the amount of recovery of purchased power expenses paid to a QF owned in part by a utility.

Pacific Gas and Electric Company (PG&E) urges that this Commission reject staff's recommendation. It argues:

> "When utilities invest in QFs the utilities' shareholders bear risks greater than those assumed in traditional utility investments. As a reward for taking the risk that expenses may not be recovered in the event of project failure, the utilities should have the opportunity to retain the full benefits of the venture, the same as any other investor in a QF. It has been determined by both the FERC and the Commission that to adequately encourage and reward investors in QF projects, the investor should be allowed to receive full avoided costs.
>
> "If the Commission wants to strongly encourage development of cogeneration and small power production facilities, it should allow utilities to participate in this energy market with incentives equal to those granted to others. The effect on the ratepayer is the same whether the power is purchased from a QF owned in part by a utility, purchased from a QF in which a utility has no equity interest, or generated from conventional resources. At the same time, a greater number of preferred resources will be developed."

PG&E concludes that such incentives will encourage utility investment in QFs, financially strengthen the utility, and improve its ability to build preferred resources, ultimately reducing the cost of serving its customers.

Edison also argues that staff's proposal is unreasonable. It contends that federal authority preempts state inter-

ference in utility - QF relations, and asserts that even without such preemption public policy considerations support the recovery of full avoided costs by the QF from the utility and by the utility from the ratepayer.

SDG&E also argues that "the supremacy clause would preclude reconsideration of whether the rates are just and reasonable for the purpose of rate recovery by the utility." It characterizes staff's position as apparently due to a misinterpretation of certain comments accompanying FERC proposed rules.

We find that staff's recommendation should not be adopted.

PURPA permits utilities to own up to 50% of a cogeneration or small power facility otherwise qualifying under the act with that facility still retaining its qualifying status. Such facilities should therefore be eligible for full avoided costs under the conditions adopted in this proceeding.

While facilities with less than 50% utility ownership are eligible for avoided cost (assuming all other requirements are met), we note that this Commission has continuing responsibility over the rest of utility operations, including financial health, which could be directly affected by a utility's equity involvement in qualifying facilities. The Commission has responsibility in three areas which are germane here.

First, the Commission must consider the potential anticompetitive aspects of utility behavior. In this regard, when a utility is approached by a large number of aspiring QFs, we must assure that its own affiliates do not receive special treatment, e.g., more rapid consideration, less difficulty in resolving interconnection issues, etc. It is important that utilities do not stifle competition in the QF market in this or any other way.

Second, there is a concern that utilities would have an incentive to keep avoided costs high (or choose methodol-

ogies that would produce such results) if their own affiliates could receive such prices. A related concern is that a utility would have an incentive to negotiate nonstandard offers that are above avoided costs if it has an ownership interest in the qualifying facility.

Our last, and perhaps most important concern relates to the fact that utility ownership of qualifying facilities would be a step toward utility diversification into unregulated activities. Any such diversification into unregulated ventures may have an impact on the regulated utility business for which this Commission is responsible. Our primary concern is the protection of the financial integrity of the regulated entity (i.e., new unregulated ventures should not impair the utility's ability to raise capital, its bond rating, etc.) and the avoidance of any subsidization by the regulated entity (and thus its ratepayers) of the unregulated business.

Utilities should be aware that while we are not denying their eligibility to participate as qualifying facilities under PURPA, such involvement will require greater scrutiny of utility operations on our part relating to the concerns addressed above. Any utility may come forward with a proposal for partial ownership of a QF and we will review these matters on a case-by-case basis, with the intent of protecting the interest of both ratepayers and any QFs who might be disadvantaged competitively.

Staff also suggests that avoided cost principles should not apply to facilities in which a utility owns an equity interest greater than 50%. Because such facilities are not "qualifying facilities" this issue is not ripe for resolution in this proceeding. Therefore, we make no judgment in this regard. Similarly, staff introduced the issue whether avoided cost principles should apply to facilities that are not "qualifying" for reasons other than ownership. The resolution of this issue is beyond the scope of this proceeding.

Advisory Services Corporation (ACS) raises the question of the extent of state regulatory jurisdiction over joint ownership arrangements where the utility owns the energy resource and the nonutility owns the facility. Staff argues that FERC does not intend that such an arrangement attain qualifying status. It states that "the underlying assumption is that the nonutility participant owns the resource which, without utility assistance in financing, would remain undeveloped." Staff contends that "the very basis for avoided cost payments does not apply to utilities developing their *own* resources," (emphasis in original) and concludes "the utility can clearly generate the energy and capacity itself, and does not require avoided cost payments."

While we are not persuaded to adopt staff's conclusion, ACS and the staff do raise an important question. Utility owned resources generally are purchased under the assumption that they will be employed on a regulated, cost-of-service basis. It is conceivable that a resource currently owned by a utility (and presumably acquired to be developed on a regulated, cost-of-service basis) could be more fully developed as a resource used in a qualifying facility. However, any profit involved in the transfer of such a resource from the utility as a regulated entity to a qualifying facility is certainly of interest, and will be considered in general rate proceedings.

The Bureau of Electricity of the City of Alameda (Alameda) cites a filing by this Commission before FERC in Docket No. RM-81-2 regarding geothermal development in which we asked that avoided cost principles not be applied to geothermal fields undergoing rapid commercial development. Alameda recommends that the Commission:

> ". . . extend to other forms of small power, biomass, or cogeneration facilities the same rationale that prompted it to seek from the FERC authority to exempt from avoided cost pricing

> standards geothermal facilities which are shown to be commercially feasible without such economic assistance. As the Commission noted in its FERC comments, avoided cost pricing does have the effect of excluding municipalities and other nonprofit entities from competing to develop geothermal sites because their avoided costs are lower than other entities, such as PG&E. Municipalities such as Alameda could be excluded from competing to develop other types of small power production or biomass generation facilities for the same reason. If in fact facilities can be developed at less than 'full avoided cost,' but are not due to the Commission's regulations, the developer reaps a windfall at the consumer's expense. This is not consistent with the public interest."

Consequently, Alameda proposes that we "retain, or if necessary seek to obtain" authority to exempt from avoided cost principles any QF where the seller is "ready, willing and able to develop on the basis of less than fully avoided costs."

We decline to adopt Alameda's recommendation, which we construe as an invitation to return to the "share the benefits" doctrine that we repudiated in D.91109. We believe that payment of avoided costs provides a basis for most fully exploiting all economical cogeneration and renewable energy resources. Although couched in the guise of promoting competition, Alameda's proposal is actually anticompetitive by limiting the selling price. However, nothing in this decision precludes a seller who is "ready, willing and able to develop on the basis of less than fully avoided costs" from agreeing to do so.

Another problem regarding the applicability of avoided cost principles is raised by Sierra Pacific Power Company (Sierra). It cites certain factors that it contends "make

Sierra Pacific unique when compared to the large California utilities used in the evaluation and analysis of Co-Generation and Small Power Production Pricing Standards," including the following:

1. In view of its relative size, a single large QF would represent a disproportionate share of its total resources.

2. Because of its location and the configuration of transmission systems its flexibility to import or export power is limited.

3. The addition of a large QF could result in substantial excess capacity.

4. Its cheapest power is purchased from Utah Power & Light Company. During particular times of the year purchases of QF power would require curtailment of Utah power.

Based on these and other reasons, Sierra recommends that "the final regulations should contain some recognition of both the size of the utility and the size of the facility."

We find that Sierra's points are well made and that its unique status is appropriately recognized. However, rather than simply seeking to excuse Sierra from applying avoided cost principles, we conclude that these concerns are best reflected in the development of Sierra's avoided costs. This approach is discussed further in that portion of this decision regarding purchase terms and conditions.

San Bernardino Valley Municipal Water District (SBVMWD) has introduced the question whether avoided cost principles should apply to diversions of water from a utility-owned hydroelectric facility. The issue is illustrated by the current negotiations between SBVMWD and Edison.

Edison contends that water diversion plans are beyond the scope of this proceeding. Water diversion is alleged

to be a matter of water law, not related to the issue of simultaneous purchase and sale between a utility and a QF. We note that this problem has also been raised in Edison's annual Energy Cost Adjustment Clause (ECAC) reasonableness review, Application (A.) 60321.

We agree that the proposed water diversion is beyond the scope of this proceeding as it does not involve a sale of electricity by a facility qualifying under FERC rules. In D.92496 we instructed Edison and SBVMWD to negotiate an agreement 60 days from the date of that decision. An extension of time was subsequently granted. We will be reviewing any agreement submitted and will take appropriate action in the next Edison ECAC filing.

IV. Purchase Terms and Conditions

A. Introduction

Under Section 210 of PURPA and the corresponding FERC regulations, each regulated utility is required to file projections of its incremental energy and capacity costs and its capacity construction schedules with its state regulatory authority for review and use in setting appropriate rates for purchase and sale of electricity between electric utilities and QFs. The first filings of these data were required by November 1, 1980. The rates determined by the Commission will be appropriate for the type of service involved and will reflect the costs avoided by the utility as a result of purchasing generation from the QF.

In determining avoided costs, the FERC regulations require that the following factors be taken into account to the extent practicable:

1. The data filed with the Commission concerning incremental generation costs;

2. The availability of capacity or energy from a QF during the system daily and peak periods, including:

i. The ability of the utility to dispatch the QF;

ii. The expected or demonstrated reliability of the QF;

iii. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement, and sanctions for noncompliance;

iv. The extent to which scheduled outages of the QF can be usefully coordinated with scheduled outages of the utility's facilities;

v. The usefulness of energy and capacity supplied from a QF during system emergencies, including its ability to separate its load from its generation;

vi. The individual and aggregate value of energy and capacity from QFs on the electric utility's system; and

vii. The smaller capacity increments and the shorter lead times available with additions of capacity from QFs;

3. The relationship of the availability of energy or capacity from the QF as derived in subparagraph 2, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

4. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a QF, if the purchasing electric utility generated an equivalent amount of electricity itself or pur-

chased an equivalent amount of electric energy or capacity.

Under FERC rules no electric utility is required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from QFs will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of power itself.

In this part of this decision we consider whether to adopt more substantial data filing requirements as proposed by staff and the extent to which the particular factors identified by FERC should be taken into account in developing standard price offers for each utility.

B. Data Requirements

Section 292.302 of the FERC regulations requires that the following data be filed:

"(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current year and each of the next 5 years;

"(2) The electric utility's plan for the addition of capacity by amount and type, for purchases

of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

"(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases."

A special rule is provided for small utilities. State regulatory authorities are allowed to impose different data requirements after notice and opportunity for public comment.

Staff proposes that this Commission require that the following data be filed:

a. System avoided operating (running) cost in cents per kWh annually and by costing period in nominal and real cents per kWh by voltage level for 10 years. The marginal fuel(s) by each costing period and the nominal and real escalation rates used to estimate their cost will be reported. System incremental heat rates by time of use for 10 years (correlated with incremental fuel costs) will also be provided.

b. The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, for capacity retirements and for terminations of contracts for purchased capacity for each year during the planning horizon, for a minimum of 10 years.

c. The estimated capacity costs at completion of the planned capacity additions and planned firm purchases, on the basis of dollars per kW,

dollars per kW per year, dollars per kW per month, and cents per kWh (using the projected capacity factor) and the associated energy costs of each unit in cents per kWh. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

d. The estimated capacity costs of transmission and distribution plant in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

e. The estimated operation and maintenance, administrative and general, and all other fixed and variable operating expenses for avoided capacity and energy used in avoided cost calculations, expressed in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

f. The system marginal cost loss factors by time of delivery and voltage for energy and capacity from generation to each voltage level. Also, the net system aggregate loss factors by time of delivery and voltage for energy and capacity, to reflect avoided losses resulting from a reasonable mix of QFs.

g. The levelized annual cost rates for translating investment costs into annual charges, and present value rates used in any present value calculations.

h. The costs expressed in paragraphs a-e above will be on a test year (real) dollar basis or on an escalated basis, with the forecast escalation rates reported in either case. All assumptions of escalation rates, discount rates, incremental

fuel increases, incremental heat rates and such, will be stated.

i. Results will be presented in summary table(s) for final total avoided costs (e.g., paragraphs a, c, d, e, f) after all effects are taken into account (e.g., losses).

The data filing is proposed to be made within 45 days of this decision and every two years, beginning June 30, 1982.

Specific reasons are offered by staff for the more thorough data filing requirements proposed. These are summarized as follows:

Avoided Energy Costs - FERC requires a five-year forecast. Staff argues that QFs are reasonably provided an estimate of marginal energy costs over the life of a contract. Forecasts of marginal costs for at least 10 years are necessary to assist QFs in determining an estimate of potential cash flows. Forecasts should be reported in terms of constant and escalated dollars.

Resource Plan The Commission should use the same costing horizon for this purpose as for others. The proposal is alleged to be "sufficient and consistent" for this purpose.

Transmission and Distribution - Whether transmission and distribution facilities are avoided by purchases from QFs is a factual question. Staff argues that avoided cost data should be filed and the matter examined, as there may be individual cases in which payment is justified.

Operation and Maintenance, Administrative and General - Such costs are either fixed or variable. When a QF provides capacity, the avoided cost should include the avoided fixed costs. When a QF provides energy, the avoided cost should include the avoided variable costs.

> *Loss Factors* - Section 292.304(3) specifically provides that avoided costs may reflect costs or savings from variations in line losses to the extent practicable. Payments to a QF serving its own load should reflect the losses avoided by the utility from not having to generate the electricity itself.
>
> *Levelized Annual Cost Rates* - Each utility should be prepared to support its calculation of levelized annual cost rates used to translate dollars per kilowatt into dollars per kilowatt per year.
>
> *Escalation Factors* - Whether costs are expressed in real or nominal terms, the utility's assumptions regarding escalation should be filed to allow parties to use their own assumptions.

The utility response is varied.

PG&E proposes to include nearly all of the staff's provisions, omitting only the reference to loss factors. SDG&E similarly proposes to include nearly all of staff's provisions, omitting only the reference to transmission and distribution plant. Edison argues that to require further data in addition to that required by FERC would be excessive, burdensome, and would not be cost-effective.

The data required must be sufficient to develop a standard offer consistent with the adopted guidelines and for qualifying facilities to reasonably forecast the direction of avoided cost over time. The staff data requirements appear to be reasonable and will be adopted. However, many data items sought by staff are included in other documents of the utilities which are required to be filed with this Commission or with the CEC. To require all of this data to be filed every two years may result in both duplicative work and inconsistent data. Therefore we do not adopt staff's proposed filing schedule. Instead, we shall require staff to submit a revised plan for the filing of data for

our consideration in further hearings. Staff shall consult with the utilities and the CEC regarding other filing requirements which currently exist. Staff's revised plan should seek to minimize duplicative filings and make available at all times the most current information available.

While we have asked staff to develop an ongoing plan for data filings, it is important that initial data filings be filed promptly. Therefore we shall require all of the above information to be filed within 45 days. These filings may incorporate data from other filings as appropriate to avoid duplication. We will consider modifying these data requirements after further proceedings on specific price offers or as needed.

The staff report addresses the questions of which utilities should be required to file data. "Sierra has not filed data under Section 292.302, but has filed marginal cost data under Section 133 of PURPA. CP National believes they should not be required to provide cost data." CP National buys its electrical requirements from PG&E and Nevada Power Company.

Staff recommends that Sierra file the specified data, but that CP National file only the rates it pays for purchases, together with the avoided cost data of its supplying utilities. CP National should be able to file by referring to the avoided cost data of its supplying utilities. We adopt the staff's recommendation.

C. The Standard Offer

1. Introduction

We have previously referred to the "standard offer". This is the expression widely used by the parties to describe the terms and conditions associated with the utility's obligation to purchase from a QF at the utility's avoided cost. The standard offer is available to all QFs, and represents a complete transaction, including prices, interconnection requirements, and other relevant factors. A central

aspect of all such offers will be the standard rates for purchase.

Section 292.304, paragraph (c), provides, in part:

> "(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.
>
> "(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts."

Standard rates for purchases may differentiate between QFs using various technologies on the basis of their differing supply characteristics and must be consistent with the factors listed in Part IV, A, above. As discussed below, in this decision we provide for standard rates for QFs of 100 kW or less and for more than 100 kW. The rate has relevance only in relation to the mutual obligations of the parties. In this decision we consider the nature and extent of such obligations. The result is the standard offer.

The standard offer has particular significance in terms of the existing and anticipated ratemaking treatment to be afforded utility purchases of energy and capacity provided by QFs. Purchases under the standard offer are *per se* reasonable and a utility's expenses for such purchases are recoverable in the same fashion as other purchased power expenses (in ECAC proceedings, for the larger utilities) without further review. Purchases at rates, terms, or conditions other than the standard offer are recoverable through ECAC or other appropriate procedures subject to a showing of reasonableness. Because of the different degrees of risk for the utility, there is widespread interest in whether the Commission will review nonstandard contracts prior to their becoming effective.

In adopting the parameters for rates that will be part of the standard offer, we are establishing a definition for a utility's avoided costs to be applied when purchasing energy from qualifying facilities under the terms and conditions of a specified standard contract. To facilitate discussion of the specific issues related to avoided costs as raised in this proceeding, we will first make some general observations.

The Commission has found in recent years that avoided cost (or marginal cost) pricing has significant benefits when applied to ratemaking. Avoided costs reflect the added costs to a utility of producing an additional unit of electricity. When marginal costs are used as the basis of rate design, consumers receive an efficient price signal. When adopted for purchasing electricity from third parties, the price encourages full economic development of those resources. Avoided cost pricing parallels the prices that would be established in a competitive market, providing many of the incentives for efficient resource allocation that a competitive market provides.

Some argue that ratepayers are disadvantaged when avoided costs are paid to qualifying facilities, because in some cases these facilities can produce electricity at less than the avoided cost price. While it may be true that some QFs could be brought on line at a purchase price below avoided cost, such a price would not be sufficient to bring in other QFs capable of producing power at prices up to the avoided cost price. The point of permitting avoided cost pricing is to encourage the fullest possible efficient development of QF resources that can effectively and economically compete with utility resources. By opening this market, the supply of electricity is increased, which should lower customers rates over time. Heavy utility reliance on oil and gas fuels to generate electricity has caused rates in California to skyrocket. Avoided cost pricing is intended to stimulate development of substantial generating capacity that will reduce utility oil and gas con-

sumption. In addition, system reliability is increased by the presence of larger numbers of smaller facilities.

If anything, this Commission believes that the avoided cost signal to QFs is a conservative one, as it does not include the tangible but hard to quantify "social costs" that are associated with new utility supplies and which are avoided through the purchase of QF power. These "social costs" include the risks associated with imported energy supplies and environmental degradation related to conventional generation. While several parties suggested that we explicitly include "social costs" in the avoided cost calculation, we are not including such factors at this time.

We prefer to recognize social costs in the general policy judgment that QF production is competitive at avoided costs. This conclusion is reflected in the terms adopted in this decision that are intended to promote QF development.

We concur with FERC rules which require full avoided cost pricing of power from qualifying facilities. The issue we face now is how to arrive at avoided cost, not whether it should be paid. This proceeding has demonstrated that defining and calculating avoided cost is far from a trivial exercise, involving conceptual, empirical, and technical issues. Some of the issues cannot be resolved without further hearings. However, we resolve most of the major conceptual questions in this decision, and this will simplify the hearings that follow.

Before discussing each of the standard offers in detail, we will discuss the relationship between the offers and the method for using avoided cost principles to derive each of the offers ordered herein.

The first type of offer described below is a standard offer for "as-available" QF power, the price which the FERC indicates should be based upon the "purchasing utilities' avoided costs calculated at the time of delivery."

The value of a unit of QF power delivered at any given point in time is equivalent to the cost that the utility would have to incur to produce an equivalent amount of power at that time. This is the short run marginal cost of electricity production in the utility system. As this Commission discussed at length in a recent PG&E rate case, (D.93887, December 30, 1981), the short run marginal cost of utility electricity production is the highest variable operating cost per unit of electricity produced at a given time plus a shortage cost which reflects the effects of the added increment of production on reserve margins and reliability. As these costs are avoided through purchases of QF power, the purchase price paid to QFs under the first offer is tied to the short-run marginal cost. This will include an "energy payment" equivalent to the utility's marginal operating cost and a "capacity payment" equivalent to the utility's marginal shortage cost. The purchase price, following the avoided short run marginal cost, varies by time of day and time of year.

The FERC rules also call for offers that are made "pursuant to a legally enforceable obligation . . . over a specified term . . . (with) the avoided costs calculated at the time the obligation is incurred." This type of offer thus takes the form of a long-term standard offer which must be based on projections of avoided costs. Such long term offers give greater certainty to both the QF and to the utility and its ratepayers. Following the same economic principles described above, we order long-term standard offers which are based on projections of the utility's short-run marginal costs. Such offers reflect the expected short-run marginal cost that the utility will avoid through purchases from QFs at each point in time over several time periods. The price includes an energy component which is tied to short run marginal operating costs in each period and a capacity component which is tied to short run marginal shortage costs in each time period. Energy payments

are allowed for up to five years, firm capacity payments for up to thirty years. A levelized payment option is ordered for capacity payments.

A final long-term avoided cost offer described below is based on projected long-run marginal costs rather than short-run marginal costs. These offers should be roughly equivalent over time, since the utility's short run marginal cost can be expected over time to fluctuate around the utility's long-run marginal cost. The latter is defined as the capital and operating costs of marginal additions to the utility's generation capacity. The avoided cost price offer that is based on the long-run marginal cost will be a more stable pricing alternative and will place system capacity additions derived from QF investments on an equal footing with those derived from utility investments. This long-term resource plan-based price offer for firm energy and capacity will be for periods up to thirty years, with energy and capacity payments tied to the utility's long-run marginal energy and capacity costs.

We note in passing that while long-run standard offers can be based on either projected short-run marginal costs or projected long-run marginal costs, there is debate on the development of the long-run marginal cost. We will reserve or further review the proper relationship of energy and capacity in the long-run standard offer.

We are ordering utilities to file an array of offers based on different terms and conditions, and to provide reasonable notice of such offers. Just as most markets develop a combination of pricing arrangements ranging from a spot price to long-term contracts, we think it is appropriate that qualifying facilities receive a variety of standardized options to better serve their particular needs. In all cases, standard contracts should be based on avoided cost principles.

2. Standard Rates for More Than 100 Kilowatts

a. In General

The nature of the standard offer to QFs of more than 100 kW is the central issue in this proceeding. The adequacy of its terms will largely determine the extent of QF production. The flexibility of its terms will determine the extent to which parties resort to nonstandard contracts.

The term "standard offer" is itself an oversimplification. This decision directs that each utility offer a choice of contract terms at the seller's option. These choices are intended to be economically equal over the life of a contract. It is such equivalence that qualifies each as a standard offer.

The context for these choices is provided by FERC Regulation Section 292.304(d):

> "Each qualifying facility shall have the option either:
>
> "(1) to provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
>
> "(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> "(i) The avoided costs calculated at the time of delivery; or

"(ii) the avoided costs calculated at the time the obligation is incurred."

Each of these choices is provided for in the "standard offer" as developed below.

b. As Available Contracts

i. Energy

The utility's avoided energy cost at time of delivery in the as-available offer conceptually is based on short-run operating costs. It should reflect the variable cost of providing an additional unit of electricity. The methodology for actually calculating this number may be refined over time, as we become more sophisticated. Also, payments may be differentiated by time of use into more costing periods in the future as technology permits.

The utility's avoided energy cost at the time of delivery for most of the utilities is currently the product of the purchase price of oil used as the marginal fuel over the last three months and the forecasted incremental heat rates (IHRs) of the plants used by the utilities to follow load.

The intent of the energy prices is to capture as accurately and timely as possible the current marginal energy cost incurred by the utility. To accomplish this the IHRs will henceforth be calculated using the current resources of the utility without speculation on the operational date or operational characteristic of major new units. The impact of major new units will be included in the calculation of energy prices only when they have actually become operational, and actual operational experience will be used to assess the impact on marginal energy costs. This is consistent with the calculation of short-run energy cost which we recently adopted in the PG&E and SDG&E general rate decisions.

Staff believes the as-available energy payment by any utility should be uniform to all QFs, treating any adjust-

ments in the aggregate. PG&E disagrees. It argues that differences between QFs should, where possible, be reflected in prices. It states:

> "Although a QF may pay for generation, transmission, distribution, and losses in its customer rate, it does not mean that its full avoided cost price should include all these items. . . .
>
> "Although certain costs are calculated on a systemwide basis for rate-making, it does not logically follow that they should be calculated on a systemwide basis for QF pricing.
>
> "It appears that FERC meant to discriminate among QFs based, to the extent practicable, on the factors outlined in Sector 292.304(e). It is up to the Commission to decide the limits of practicability in reflecting these factors in purchase prices for QF power."

PG&E recommends that transmission and distribution costs not be incorporated in the standard price offers based on full avoided cost. It also proposes to evaluate line loss impacts on a case-by-case basis.

We adopt the notion of a uniform energy price. Transmission and distribution costs should be analyzed in the aggregate and appropriate adjustments made. We conclude that it is not practicable to treat such factors on an individual basis. Costs or savings resulting from variations in line losses should also be aggregated for standard offer purposes except for remote sites. It is unreasonable to reduce the payments to centrally located QFs because of higher line losses that are experienced by a utility in receiving power from a large remote QF. Losses will be examined individually for projects one MW or larger developed at sites remote from load centers where the incremental loss increase resulting from substitution of QF generation at the remote site exceeds 150% of average

transmission systems losses. Losses will be examined individually for such remote facilities.

ii. Capacity

The most controversial issue in this proceeding is the nature of the obligation to be undertaken by a QF in order to qualify for capacity payments. The general utility position is that energy provided by a QF on an as-available basis does not allow a utility to avoid any capacity costs. PG&E does recommend that utilities pay for as-delivered capacity at 35% of the current single-year capacity price, but states that this Commission must recognize that such a payment is intended to "encourage" the development of QFs. "The utilities will not be able to justify these payments as true avoided costs unless and until data not now available are collected and studied."

The intended beneficiaries of PG&E's proposal are not impressed. There is no recognition on their part that a 35% payment would "encourage" their participation. Two alternates have emerged: payments based on 50% or 100% of the capacity value.

Staff offers an analysis that suggests that the threshold question is philosophical whether to treat QFs as an increase in supply, or as a reduction in demand. While various parties complain of the oversimplification that results from such labels, the concepts have proven analytically useful.

If QF production is treated as an increase in supply, objective performance standards are appropriate. "As an increase in supply, the value to the utility depends on whether the utility has control of the power (dispatchability), whether the electricity is reliable, is available for more rather than fewer years, is available during emergencies and so on." This is the approach favored by the utilities.

According to the staff, much more lenient requirements are appropriate if QF production is treated as a reduction in demand:

> ". . . the QF need not be dispatchable by the utility in order to qualify for the full avoided cost rate. The QF need not produce a certain predetermined reliability. The QF need not sign a long-term contract and be subjected to termination penalties and sanctions for noncompliance. The QF need not schedule outages with the utility, or supply power (decrease demand) during emergencies."

This approach is generally supported by prospective QFs and is characterized as consistent with marginal cost-based rates.

Staff does not propose to limit the reduction in demand approach to QF production serving only the QF's own load. It states that treating positive net input to the system as a decrease in demand is appropriate:

> ". . . (1) if one is willing to depend on the QF market and QF equipment to insure supply just as one depends on the customer market and customer equipment to insure demand; (2) if one views QF electricity as a reduction of the number of megawatts the utilities of California must supply (since demand is reduced) rather than as a fixed resource in the resource plans for California utilities; (3) if one believes the effect on the electric system is the same from a QF reducing demand on the utility (freeing utility plant for other use) as from a QF providing a positive net input; (4) if one believes the underlying economic forces will control the relationship without the need for objective performance standards; (5) if one is willing for ratepayers to assume some risk for the development and operation of the QF market

> comparable to the risk ratepayers now assume for utility-owned plants; (6) if it is administratively infeasible to enforce objective standards in some cases (especially very small QFs); (7) if one desires to give QFs the most freedom reasonable to build and operate their facilities according to the economic forces which permeate the relationship; (8) if full avoided cost rates do not allow the utility to control an investment owned by others; and (9) if the lessons of conservation have taught us that a reduction in demand is the same as an increase in supply."

Although the staff report discusses each approach at length, staff takes no position regarding this issue.

SDG&E supports the "increase in supply" approach and contends that this Commission is without discretion to do otherwise. It argues that the FERC regulations require the consideration of the particular factors enumerated in Part IV, A above, and states:

> ". . . it is practicable to apply many of the factors pertaining to capacity to the individual capacity rate. Staff would not apply some of the factors even though it is practicable to do so because of its philosophic debate as to whether QFs should be treated as an increase in supply or a decrease in demand. Since the PUC does not have discretion to refuse to apply a factor once it is determined to be practicable to do so, the debate should be pragmatically resolved in favor of treatment of QFs as an increase in supply."

SDG&E further contends that aggregate capacity is not practicably reflected.

Edison states that energy provided by a QF on an as-available basis does not allow a utility to avoid any capacity costs:

> "It would be imprudent indeed for a utility to defer or refrain from installing capacity resources on the mere hope or even expectation that enough as-available energy will be available when needed to meet the peak load imposed with a prudent reserve margin.
>
> "Prudent utility planning requires that sufficient committed capacity be available when needed to meet the peak load imposed with a prudent reserve margin."
>
> * * *
>
> "Even if a QF is contractually bound to provide capacity resources, the length of that contractual obligation will determine how long a utility is able to defer a capacity installation, and therefore, the actual capacity-related cost which will be avoided."

Edison does support a "pay for performance" concept which Edison states "neither assumes a capacity value nor does it assume no capacity value." It is alleged to pay a QF for its true capacity value regardless of technology.

As stated earlier, PG&E does propose a payment for as-delivered capacity, though it contends that its proposal cannot be justified in terms of true avoided costs. PG&E expressly supports the "increase in supply" approach. It argues:

> "A QF willing to give PG&E more control over its generation by accepting performance standards and contractual obligations has a higher value to the utility. The performance of a QF selling contracted capacity will be measured to evaluate its equivalence to utility generation. In cases of Firm Capacity, it is PG&E's position that objective standards, termination provisions,

> and sanctions are absolutely necessary. Price alone does not provide sufficient incentive to deliver the capacity when it is needed."

PG&E proposes that QFs selling contracted capacity will be paid up to the full cost of a PG&E resource, and that such payment can be made on a levelized basis.

Nonutility parties generally support the "reduction in demand" approach. CEC states that the "demand reduction" model is clearly superior:

> "Treatment of (QFs), at least below 50 megawatts in size, as miniature power plants does not reflect the aggregate benefits to the system which result from their small size. We note that the aggregate experience of a group of (QFs) will be better than the experience of any individual (QF). This is a case where the whole is greater than the sum of the parts. This is particularly important for wind generation, where the dispersion of windmills over a large geographic area may result in more benefits to the system than the sum of individual windmill capacity values or individual windfarm capacity units. The key to correct pricing for performance of small units is recognition of the diversity of outages in small units. Utilities have recognized this diversity for years in developing rates and demand forecasts for customer classes; yet they by and large propose not to use this conventional analysis for small dispersed generators.
>
> ". . . The application of reliability and dispatchability criteria applicable to the supply model by utilities would result in underpayments to (QFs) relative to aggregate performance and even relative to performance of conventional power plants. Our detailed examination of the wind contract for PG&E, for example, indicates that if

> Rancho Seco were a windmill (or any type of (QF) for that matter), it would not receive capacity payments."

CEC supports a time-differentiated capacity payment in cents per kWh, paid for performance.

The Natural Resources Defense Council, Inc. (NRDC) also supports the "demand reduction" approach. It criticizes the "supply increase" method as overlooking:

> ". . . the difference in size of supply provided by a QF and a regular power plant. Where QFs are small their lack of availability will have far less impact on the utility system than would a failure by a major power plant."

It states that performance standards fail to provide recognition of reliability obtained by aggregate performance. "QF reliability will be increased by the use of time-differentiated rates, which will encourage QF generation during periods when it is needed most." Due diligence is cited as the only necessary condition.

MPS supports the "reduction in demand" approach as conceptually accurate:

> "Where the utility has no direct control of the customer's resource (generating equipment), the utility only experiences customer generation as a reduction of load. The utility serves a different demand curve than it otherwise would. Since the demand curve is the direct determinant of the utility's incurred costs, the alteration of this curve is the utility's avoided costs. It should be noted that the only effect experienced by the utility generating stations is the total reduction in system load caused by the instantaneous sum of all customer generation. This is an accidental result, exactly like the accidental result of all customer load, the traditional demand curve."

It argues that since both consumption and generation have exactly the same effect on the utility's load curve, the established method of regulation of sales serves as an excellent model for regulation of utility purchases.

Henwood Associates, Inc. (Henwood) agrees that "as available power will exhibit predictable patterns in a fashion analogous to customer demands."

> ". . . It should be recognized that this is a result which depends upon the number of QFs being present in the market-place and that a transition period will occur between now when few producing QFs are in existence and later when the requisite number of QFs have succeeded with their plans.
>
> "This transition period gives rise to an argument which (may be called) the chicken and egg argument. . . .
>
> "In essence this argument goes that without many QFs, the aggregate capacity value of as-available energy does not exist; hence no capacity payment is required.
>
> "This, of course, reduces the price paid to as-available QFs, thereby reducing the number of viable projects in strict conformance with well-accepted economic theory.
>
> "The ultimate result, of course, could be insufficient QFs ever to justify as-available capacity payments.
>
> "Now the converse to this argument is that if as-available capacity payments are made now, this may induce more QFs to come into being, thereby justifying these payments.
>
> "It appears that the choice of authorized payments revolves around the expectation of success or failure of the small power production program.

> "If success is expected, then as-available capacity payments are justified from the outset.
>
> "If failure is expected, these payments are not justified at the outset and could only be justified with later success of the program."

In view of the purpose of PURPA, Henwood argues that "success" should be a basic assumption underlying this decision.

Additional comments in this regard are offered by various nonutility parties.

We have quoted these parties at this length to indicate what we find to be compelling reasons supporting the "reduction in demand" model. Consequently, we will provide for capacity payments for as-available energy as part of the standard offer.

The "as available" capacity price we will adopt in this proceeding is based on the shortage concept as expressed earlier, which is based on the utilities' short-run marginal cost. The capacity then is consistent with "as available" energy payments, which are also based on short-run marginal cost. We agree with the parties who recommended that capacity payments be time differentiated, to reflect a higher price during peak periods when the possibility of shortages is greatest.

We are not dissuaded by SDG&E's legal argument that we lack discretion in this regard. As stated above, the standard rate must be "consistent" with the provision that certain specified factors shall be taken into account "to the extent practicable." One of the factors is:

> "(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system."

FERC plainly intends that aggregate capacity value be recognized.

We do not find that aggregate capacity has an equivalent value to firm capacity. To the extent that an individual QF is willing and able to contract to provide firm capacity additional costs can be avoided which should be reflected in the payment to the QF. These are provided for in the firm capacity offers presented below in which QFs receive full annual capacity payments based on specific performance commitments.

Having established the acceptability of a capacity payment for as-available energy, we now address the question of whether a QF producing electricity on an as-available basis is entitled to 100% of capacity value. If there is a capacity value recognized for as-available energy, staff recommends:

> ". . . initially a capacity payment be made in cents per kilowatt-hour assuming a 50% capacity value derived from full 25-30 year avoided capacity cost at 100% capacity factor. . . . That is, offers will be based on the assumption that every 2 kilowatts of installed capacity from intermittent sources provides for a flow of electricity which will allow the utility to avoid 1 kilowatt of capacity. The payment should be by time of delivery for large QFs and be at the option of the QF (depending on the meter the QF installs) for small QFs by either time of delivery or on an average basis."

As stated earlier, PG&E proposes that a 35% value be assigned. There is a wide difference of opinion among the parties regarding the resolution of this issue.

NRDC asserts that staff's recommendation undervalues QF contributions:

> "On the one hand, it could mean that a QF would receive a payment in cents per kilowatt-hour for the value of one-half of its installed capacity, op-

> erating at a 100% load factor. . . . However, the ambiguity of the wording could allow the interpretation that a QF would receive credit for only 50% of the capacity value actually provided."

It argues that QFs whose capacity factors typically exceed 50% should get corresponding capacity credit.

Several parties argue that the staff proposal is inadequate. Pan Aero Corporation (Pan Aero) argues that:

> "As to aggregate capacity value, the aggregate capacity value for as available capacity should be 100%, not the arbitrary 50% as recommended in the report.
>
> "Aggregate capacity should be prorated to cents per kilowatt-hour so that the full value is earned if the QF capacity factor is equal to the typical capacity factor of utility oil plants."

MPS agrees that 100% is the indicated capacity value and contends that even at that level QFs will be underpaid, "because of the inherent tendency toward daytime production possessed by all qualifying resources combined."

Metropolitan Water District of Southern California (MWD) argues that staff's proposal does not conform to FERC's intention that the fully avoided capacity cost be reasonably allocated, based on the QFs individual supply characteristics.

> "However, a reasonable allocation of the full-avoided capacity cost can be properly obtained through the staff's suggested option of time-differentiated capacity payments. Basically, this amounts to distributing the utility's full-avoided capacity cost by time period based upon a 100-percent capacity factor plant during each respective time period."

In this way the payments for capacity would be based totally on the performance by time period.

Edison supports the "pay for performance" concept which it contends renders unnecessary an assumed capacity value. Its proposed method is described as follows:

> "To be eligible for full capacity payment, a QF must attain a monthly capacity factor of 51% or greater by time period. The payment is based on the QF's monthly capacity factor by time period times the full capacity payment. Below 51% capacity factor, the capacity payment is reduced by 50%. The payment is then based on the QF's monthly capacity factor by time period times 25% of the full capacity payment, as the capacity factor of the QF increases or decreases, capacity payment increases or decreases proportionally."

This method is alleged to work regardless of technology.

SDG&E argues that the 50% aggregate capacity value is arbitrary and that it will be denied due process of law if such a value is adopted. It maintains its position that no capacity payment should be made.

The issue of the extent to which as-available energy will receive a payment for capacity value is inextricably related to the method used to estimate capacity value. Staff proposes that the capacity payments for as-available be in cents per kWh, by time of delivery and voltage, based on 25-30-year avoided capacity costs. SDG&E complains that there is no foundation for the assumption that QFs who supply aggregate capacity will do so for 25 to 30 years. It contends that:

> "To require current ratepayers to pay today's QF the value of a 25-30 year contract on the 'crystal ball' assumption that a new QF will replace him in the future to complete a 25-30 year term is

> again a blatant subsidy to the QF at ratepayer expense."

It argues that the length of the contract should determine the calculation of the appropriate capacity value.

PG&E proposes using the single-year capacity price, rather than the 25-30-year levelized price recommended by staff. It argues:

> "Our proposal results in a much simpler standard offer. If a single year value is used, there is no need for contract length, notice, termination or sanction provisions. If a levelized value is used, such provisions are necessary to recapture excess capacity payments if a QF fails to operate for the extended term. Under our proposal all QFs would be paid the correct amount regardless of the life of their project. A QF who operates for 30 years will receive the same life cycle payment as if he had been paid a 30 year levelized value. A QF who operates for 10 years will receive the same life cycle payment as if he had received a 10 year levelized payment."

Since the single-year capacity price changes each year, all QFs selling as-available energy will receive the same capacity price.

The consensus that does emerge from all of this is that the aggregate capacity payments should be based on performance, adjusted by time period. We agree that staff's proposed 50% value is ambiguous, arbitrary, and should not be adopted.

Instead we adopt a capacity payment for power from as-available sources equivalent to 100% of the shortage value of such power, as described in the following paragraph. This payment will be made in cents per kWh, will vary by time of delivery, and will be paid for each kWh

produced and delivered by the QF. Thus actual performance will determine the amount of the capacity payment.

As we have already discussed, the capacity payment we adopt on an as-available basis is based on a short-run avoided cost methodology. We will therefore not adopt the staff's recommendation of a forecast of future year capacity costs, but instead require utilities to use estimates of current shortage costs. For PG&E, in its most recent rate case, 100% of the annual capacity cost of a gas turbine was estimated to be the correct proxy for current shortage costs. PG&E allocated this capacity cost by time of day and time of year in a way that reflects the shortage cost incurred by marginal additions to load in each time period over the year. This approach would appear to be appropriate for our present purposes. Accordingly, PG&E, Edison, and SDG&E shall determine the as-available capacity price based on the 1982 estimated cost of peaking capacity (utilizing a combustion turbine facility as a proxy). Sierra shall determine the as-available capacity price based on the avoided (marginal) capacity costs as determined in the most recent case.

Costs should include generation and generation-related transmission. Contract length, notice, termination, and sanction provisions are not related to as-available offers, and should therefore not be included.

Aggregate capacity value will be available as a cents per kWh addition to the energy price only for energy delivered through a meter to the utility. The QF choosing the interconnection option of simultaneous purchase and sale will receive explicitly an aggregate capacity value for all energy generated, as the entire generator output is metered at the generator before any energy goes to the QF's load and to the utility. Under the sale of surplus power option, however, the meter at the point of interconnection with the utility will only measure that surplus portion of the generator's output which is delivered to the

utility after the QF serves its own load. Thus the QF will receive, in payments by the utility, only a portion of the capacity value for the total output of its generator. The remainder of the capacity value of the generator's output will, however, be recognized in the form of utility charges (including charges for capacity), which the QF will avoid by serving its own load.

There does appear in the record an issue regarding the appropriate capacity payment for small hydro facilities. Different treatment may be reasonable for hydro because of the probability that a large portion of the resource will fail simultaneously for an extended duration, limiting its aggregate value. The problem is compounded by a concern that hydro would be overvalued during wet years when capacity is relatively better than dry years.

The different points of view are summarized by Henwood:

> ". . . PG&E has proposed to use the absolutely worst year of record, 1977, to establish capacity values.
>
> "That naturally results in the minimum capacity value assignable to the hydro plant.
>
> "Staff, on the other hand, proposes to use the average of dry years.
>
> "Now, to my knowledge, there have been no conclusive studies ever performed which establish the best way to value hydro capacity in utility systems.
>
> "In fact, the Idaho Power Company plans capacity using the average hydro conditions, despite the fact that more capacity and more energy in their system comes from hydro than does in PG&E's system.

> "Since the industry itself values hydro capacity conditions nonuniformly, our recommendation is that much more thought, perhaps even in the form of a PUC or Energy Commission sponsored study into this area, should be given to the question before this very important and fairly permanent pricing treatment of hydro capacity contributions is set by the proceedings.
>
> "The other problem we see is when steam-flow gauging records are insufficient or unavailable, as is the case in many of the smaller projects being developed in California.
>
> "Of the seven projects our firm is currently involved in, only three have gauging records, and none of the projects have gauging records of a sufficient duration for PG&E's proposed 50-year water study."

We believe that capacity payments for as-available hydro should not differ from other technologies. Instead, as the methodology is perfected for calculating as-available capacity costs, the as-available payment should be low during wet years relative to dry years because the chance of shortages is lower in wet years.

Staff recommends the deletion of PG&E's Factor F-1, which makes adjustments to energy prices to small hydro QFs for the effect of hydro conditions on incremental heat rates and fuel inventory. PG&E argues that, if Factor F-1 is eliminated, its avoided cost prices would have to be increased. Its energy prices are based on forecasted avoided costs which do not consider cost impacts due to variations in hydro conditions. QFs generally oppose the imposition of Factor F-1.

We conclude that Factor F-1 should not be allowed. We are not convinced by PG&E's arguments that its computation of avoided costs should be modified by the elimi-

nation of Factor F-1. These arguments should be considered together with a complete examination of the computation of marginal energy costs in the compliance review to follow. Because most small hydro projects are in the planning stage, this delay will not have a significant cost impact to PG&E.

c. Long-Term Contracts

i. Energy

The FERC provides the seller of energy with the option of payments based on either (1) avoided costs calculated at the time of delivery, or (2) avoided costs calculated at the time the obligation is incurred. Payments under the first option should be the same as payments for as-available energy, as provided above. Payments under the second option require long-term energy price offers.

A major issue in this proceeding is the terms utilities should provide to QFs for commitments to deliver energy in future years. In this section we will discuss the issue of establishing a price for the energy portion of avoided cost based on a forecast of energy rates in the future. Many argued that utilities should commit in advance to future energy rates, and further recommended that the Commission order a levelized payment option as well.

A long-term energy price offer allows both a QF and the utility the certainty of a known price which can be valuable for planning. We therefore will order utilities to file a proposed price offer which commits both the utility and the QF to energy payment prices for up to five years, based on a forecast of the utilities' variable costs. Under such an offer, the QF must commit to provide all the energy it produces to the utility over the contract period. We will order the offer to be a proposal for review in hearings by other parties before it becomes effective. This price offer will be available to all QFs.

Staff proposes that the QF be allowed the further option of levelizing the price so that a greater portion of the total payment is received in the early stages of the contract. FERC comments addressing this provision expressly provide for the levelization option:

> "A facility which enters into a long term contract to provide energy or capacity may wish to receive a greater percentage of the total purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or nonregulated electric utility from approving such an arrangement."

Thus we have the discretion to provide for levelized payments as part of the standard offer.

Edison opposes levelized energy payments. It characterizes the necessary estimates as "purely speculative", and not reliable. It argues:

> "Paying levelized costs for an increasing cost stream is unfair to present ratepayers because it results in paying for a benefit before that benefit accrues. Even five-year levelizing has this effect, and the proposed ten-year levelizing, coupled with the total inability to accurately predict future fuel costs, represents an impermissible burden on ratepayers and is not necessary to encourage QF development."

Edison proposes that if levelized payments are required, the payments should not be allowed to exceed 85% of

avoided energy costs levelized over a period of not more than three years.

PG&E also opposes levelized energy payments because it "presents too many risks" for the ratepayers. It agrees that if the Commission requires such payments, a reduction from the avoided cost should be authorized. It further recommends:

> "Energy contracts under such circumstances should be limited to an appropriate term. This will reduce exposure to forecast uncertainty and early termination due to a QF's failure to perform. The potential overpayments using levelized energy prices are enormous, and in the event of early termination, large sums will have to be recaptured from the QF."

The problem increases as the length of term increases.

PG&E also recommends that levelized payments not be available to cogenerators using oil or gas.

> "Because of the high operating costs of these facilities, the QF's revenues must escalate to track the increasing project fuel costs. If a levelized energy payment is available to QFs using oil or gas, it is likely that those QFs will begin incurring operating losses before the end of the contract life."

It warns that QFs will not continue to operate merely because they made excess profits in the early years of their projects.

PG&E does not necessarily oppose all forms of levelized energy payments. It proposes that in the case of nonstandard contracts, it can assess the ability of the QF to perform over the duration of the levelization period and provide for such payments if appropriate.

SDG&E also opposes levelized payments. It warns that "levelized energy payments will result in up front financing as overpayments will occur in the early years."

Several nonutility parties support levelized payments. California Energy Commission (CEC) analogizes levelized payments to insurance contracts, and argues that ratepayers and QFs both benefit, assuming forecasts are reasonable. Ratepayers

> ". . . cannot gain if costs are less than forecast, but they are also protected from higher avoided costs than with forecasted and protected from consequent economic losses.
>
> "This isn't putting a risk on the ratepayers. It is giving them certainty. At the same time it also protects the QFs.
>
> "The QF doesn't gain if the utility underforecasts and oil prices are actually higher, but the QF is protected from losses if the utility overestimates future costs."

CEC does agree with PG&E that levelized payments should not be made to QFs using oil or gas as a fuel.

Levelized payments are also supported by the jointly filed comments of Great Western Malting Co. and Windfarms, Ltd. (Great Western). They consider such payments "critical" to some QF's for financing purposes. They oppose the discounted payments proposed by the utilities:

> "The utilities' argument that levelized energy payments should be discounted incorrectly assumes that the risk that levelized payments will inaccurately forecast actual energy costs falls solely on utilities or their ratepayers."

They contend that the QF also takes a substantial risk that actual costs will exceed estimated costs.

They further object to the argument that a discount is appropriate because large numbers of QFs will not fulfill their contracts. They characterize this premise as based on unsupported assumptions.

We conclude that levelized payments should not be included as an option under the standard offer. We recognize that levelized payments can encourage QF development by improving QF access to financing, and therefore consider this type of payment schedule to be desirable in some cases. However, because levelized payments can create added risks for ratepayers and because the magnitude of this risk depends completely on the specific QF project in question, we find that levelized payments are more appropriately considered by the utility and, if necessary, the Commission on a case-by-case non-standard contract basis.

Levelized payment schedules create potential risks to ratepayers that are not present in other types of long term QF contracts such as that adopted above. In the process of paying the QF prices in excess of avoided costs in the early years of the levelized contract, the utility and its ratepayers bear the risk of contract non-completion due to project failure. If a contract is terminated early because of project failure, the ratepayers will have paid costs in excess of the value of the power received and will not receive that countervailing benefits that would normally accrue during in the later years of the levelized contract. The degree of such project risk that is actually present can be expected to vary significantly from one QF to another, and will depend on the technical and economic characteristics of the specific QF project. Therefore, it is not appropriate to offer this payment option on a uniform basis to all QF's under a standard offer that is deemed *per se* reasonable for ratemaking purposes. Rather, such risks should be considered by the utility on a non-standard contract basis after review of the specific QF project in question. If necessary, such contracts can receive Commission scrutiny under our non-standard review process.

The non-levelized energy payments under the long term energy price offer described in this section may be tied to either as available capacity payments provided for in the last section, or to a firm capacity payment using a short run avoided cost methodology, which we will describe next.

ii. Firm Capacity

As stated above, FERC regulations provide for payments for firm capacity, based on avoided costs calculated either at the time of delivery, or at the time the obligation is incurred. There is no hesitation on the utilities' part to pay for firm capacity, within the limitations of their own resource plans. For standard offer purposes firm capacity is properly recognized as an "increase in supply" with corresponding standards, termination provisions, and sanctions.

The firm capacity payment properly reflects the factors recited in Part IV, A, above related to the availability during the system peak periods, including:

a. Dispatchability,

b. Reliability,

c. Contract duration, termination, and sanctions,

d. Scheduling of outages, and

e. Availability during emergencies.

The value of each of these factors shall be calculated, based on standards comparable to performance standards the utility would impose on its own plants. These standards must, however, be fair to QFs and not impose unnecessary burdens that will discourage that development of these preferred resources. The sum of each of these factors and the resultant capacity value will be offered on both a dollar per kW per year and a cents per kWh basis as currently done. A QF that exceeds operating standards normally expected of utility plants should be able to earn a higher capacity payment.

The firm capacity contract may be tied to energy payments as-delivered (similar to the energy payment in the as-available section) or to a contract for energy payment in future years as provided in the previous sections. The firm capacity payment discussed in this section is based on a short-run marginal cost methodology, in which the capacity payment reflects the costs of a shortage.

Both the firm and the as-available capacity payments ordered by this decision are based on the shortage cost concept. However, QFs with firm capacity contracts may receive a higher payment than QFs with as-available contracts. For example, a QF with a firm capacity contract that operates with a capacity factor similar to utility plant could receive the full annual capacity payment. As-available QFs would receive only a percentage of the annual capacity value for similar performance because the annual capacity payment is allocated in cents/kWh for as-available capacity.

The value of firm capacity will be based on the avoided (marginal) capacity cost used in the utility's last general rate case.

As discussed above, FERC allows for the option of levelized payments if the QF chooses payment based on avoided costs calculated at the time the obligation is incurred. The option for levelized capacity payments for periods up to 25 to 30 years as currently offered, should remain.

Dispatchability will be achieved in price offers by time basing capacity and energy prices and by requiring the QF to maintain availability during peak load periods with a reasonable allowance for forced outages. QFs will be expected to operate at maximum capacity on notice to meet utility needs for capacity during peak load periods and emergencies, consistent with limitations which may exist at the time in the QF's equipment or fuel, water, wind or other source of energy supply. Cogenerators also

will, at times, have limitations on their ability to utilize the process heat produced at maximum capacity.

For receipt of a firm capacity payment, reasonable contractual requirements for reliable operation and availability during utility system peak load periods are necessary where QFs are to receive the full avoided cost capacity value. Contractual requirements must, however, be simple and not restrictive to the point of seriously discouraging QF development. QFs should not be expected to operate with a reliability greater than the utility plants they displace. Likewise, the QF can be required to maintain an availability during system peak and mid-peak load periods comparable to, but not greater than, utility plants displaced. Where resource limitations exist to reliable operations, such as with wind parks, plant capacity factor may be a better measure to use in contractual requirements for reliable operation.

In discussing rates for supplementary and maintenance power, we determine that demand charges incurred during periods of scheduled maintenance should be waived during such periods under tariff schedules for standby service. It is waiver applies to QFs selling surplus power to the utility. It is reasonable for a utility purchasing firm capacity from a QF to require that the QF schedule maintenance of that generation during periods established by the utility. The utility will provide reasonable periods for QF scheduled maintenance and only request deferments in the customer's requested maintenance schedule on 60 days' notice. Capacity payments will not be reduced during scheduled maintenance periods. QFs on simultaneous purchase and sale contracts will continue to pay for any energy (kWh) and demand (kW) used during scheduled maintenance periods at regularly filed tariff rates.

Special provisions are necessary for small hydro QFs offering firm capacity to reflect adjustments for dry year unavailability. Two options shall be offered hydro QFs

larger than 100 kW for determining their base stream flow and monthly firm capacity rating. Option 1: the QF may use flow data directly applicable to the QF's facility, when available. Alternately under Option 2 the QF may use the flow data for the closest adjacent and similar area to the QF's facility. Capacity values for Option 2 shall be developed by areas sufficiently limited in size so that the true value of local areas is not lost or obscured. Capacity values for Options 1 and 2 shall be paid in dollars per kW per month and shall be subject to the provisions required for firm capacity.

For Options 1 and 2, the minimum June through August flow, from which the monthly firm capacity rating is derived, will be based on the five lowest flow years, as proposed by CEC, taken from a 50-year minimum continuous record. Where 50 years of data cannot be developed, utilities and QFs should agree upon a shorter time period with fewer minimum flow years averaged into the monthly capacity rating.

The price offering for small hydro QFs should include an illustrative example of the development of monthly firm capacity ratings based on dry years stream flow data. The price offer will also specify the data on stream flow required by the utility.

In its preliminary report staff recommended that utilities be required to provide QFs the option of a full capacity payment "up front", because the utilities would make such investments in the absence of QF development. The reaction of the parties was mixed. In its final report staff recommended that up-front capacity payments not be required as part of the standard offer.

Several parties continue to support up-front payment. The California Manufacturers Association (CMA) suggests that:

> ". . . in some cases it may also be appropriate to provide the QF the option of an up-front payment. An equitable method would be to place these payments in rate base amortize them over the life of the contract, and remove them from rate base using the same standards and procedure for removal of utility plant."

The risk for the utilities would be largely eliminated.

CEC originally supported up front payments but, like the staff, changed its position. The utilities unanimously object to up front payments, arguing generally that the resulting financial outlays would strain their financing abilities while imposing an additional risk relative to the capability of a QF to perform.

Staff considers this issue deserving of further study.

> "The complexities of the issue of up front capacity payments deserve additional research before such payments are required as options in standard price offers. This research will accomplish such objectives as identifying and analyzing: (1) the conditions under which such payments would financially strain utilities; (2) the implications of putting such payments in rate base; (3) the juxtaposition or fairness of the utility being somewhat like an owner (having paid the utility's avoided capacity cost which may pay most or all of the QF's capital investment costs) but not having control of the facility's management or operations; (4) the actual usefulness of up front capacity payments since such payments as now proposed would be at the first operation of the QF (after construction and financing are complete); and (5) the proper assessment of risk (such as QF risk from proper avoided cost calculation, recognition of only the risk to ratepayers of QFs,

> or a net assessment including the risk to ratepayers of utility operations)."

In the meantime staff expects utilities to develop prudent alternatives to the standard offer and suggests that innovative proposals be considered by this Commission in its evaluation of utility efforts to develop alternate energy sources.

We are satisfied that up front capacity payments are not reasonably included as part of the standard offer. We agree that such payments could introduce an element of substantial risk into the standard offer. Since the QF has sole choice among the standard offer provisions, the utility would be precluded from exercising discretion regarding the suitability of a particular QF in regard to its ability to perform. Such discretion is critical to orderly undertaking of such risks.

Such payments are reasonably considered outside the context of the standard offer. Utilities are free to agree to such provisions on a negotiated basis and to seek whatever ratemaking treatment may be shown to be reasonable. There is no need for additional study of this issue.

iii. Energy and Capacity: Long Run Marginal Cost

Several parties addressed the problem of matching together the appropriate energy and capacity payments to ensure the QF is paid the full avoided cost. This issue is of particular concern to QFs that wish to enter into long-term contracts without ending up in a situation where their payments are based on a combination of today's low capacity cost (based on a gas turbine) with low energy costs in the future (due to new baseload generation). The problem is discussed by staff, but in the opinion of Dr. Harry Davitian, representing the San Diego Energy Recovery Project (SANDER):

> "To phrase the problem with the staff's approach in its simplest form, there is no connection made

> between the computation of avoided energy costs and the computation of avoided capacity costs, even though in actuality there is a direct relationship."

Davitian contends that since utilities are emphasizing the construction of capital intensive, low variable cost capacity, the bulk of the costs avoided in the future will be related to capital investments in the purchase of capacity, not to variable costs. A computational approach that does not adequately reflect such savings in capacity costs will not provide the proper pricing signal to cogeneration and small power-producing facilities.

Davitian asserts that the staff's approach is impossibly vague. He proposes a method called a "differential revenue requirement approach", which he describes as follows:

> ". . . the utility's total annual costs, including all fuel, operating and maintenance costs, capital amortization, taxes, etc., are estimated, both with and without a projected contribution of power from the qualifying facility or type of qualifying facilities.
>
> "The difference in the two costs is directly attributable to the contribution of power from the qualifying facilities.
>
> "To properly account for the changes that might occur in the utility's capacity purchases, purchase power agreements, sales of power agreements and the associated changes in energy costs, a capacity exchange model is used in this type of calculation.
>
> "In each year of the study period, a differential cost can be established and can be expressed in terms of cents per kilowatt-hour of power provided by the qualifying facilities."

The energy and capacity components of the avoided costs can then be derived.

Great Western also complains that staff's proposed methodology is not adequately explained. It offers its own proposal for matching energy and capacity:

> "Capacity payments, on either an as-delivered basis or by contract, should reflect the avoided costs of a utility building a plant solely for capacity, i.e., the avoided cost of a combustion turbine or combined cycle facility. This sort of a plant would remain the yardstick for the capacity payment throughout.
>
> "The energy payment should be made up of two components. First is the utility's avoided running costs for its marginal plant - the costs of fuel, operations and maintenance, etc. Second, if the marginal plant in the utility's resource plan is something other than a low capital cost combustion turbine, the additional capital costs of that plant, over and above the capital costs of a combustion turbine, should be allocated to the energy payment. This accurately reflects the fact that, when a utility expends the additional capital necessary to construct a coal-fired thermal plant, for example, it is doing so not simply to build capacity but to reduce future energy costs. If the utility simply wanted to build capacity, it would build a low capital cost combustion turbine. The additional capital spent should therefore be considered an energy cost. Thus, if this additional capital expense is avoided, due to the fact that QFs are generating electricity, that fact is properly reflected in the energy payments to QFs."

In addition to linking energy and capacity payment, this method is alleged to reflect a utility's actual resource plan and therefore its actual avoided cost.

As we discussed in the introduction to this section, we stated that avoided costs can be developed based on a short-run concept or a long-run concept. Either concept is appropriate for developing standard offers assuming suitable terms and conditions are associated with the offer. The offers discussed thus far in this decision are based on short-run avoided costs. Because of the concern of the parties that short-term avoided cost may be too volatile, and may not adequately reflect the QF's value in the utilities' long-range resource plans, we acknowledge the desirability of an offer based on long-run avoided cost principles. Therefore, we will order utilities to file a proposed offer using long-run avoided costs within 90 days of this decision date.

In order to assure full examination of alternative approaches in the evidentiary proceeding, PG&E, Edison, SDG&E, and PP&L are directed to develop avoided costs and a price offering based on their resource plans. The cost data and price offering should allow up to a 25-year contract with a firm pricing structure for capacity and energy. Long-run marginal cost estimates will be based upon the fixed costs associated with the utility's resource plan and its system projected marginal operating costs. The recommendations of Davitian and Great Western are also to be analyzed by the utilities and discussed in their presentation.

iv. Bond guarantees

CEC argues that the standard offer should also provide for cost-based bond or loan guarantees.

> "A cost-based loan or bond guarantee is a contingent liability undertaken by a utility at its cost which guarantees the repayment of a bond or loan for a (QF). Given the utilities' size and position in the typical power sales agreement, they can 'package' projects that need these guarantees for 'reinsurance' with other investors, or self 'in-

> sure' with sinking fund type accounts levelized over the project.
>
> "Bond or loan guarantees may be the only way in which many municipalities and smaller developers will be able to get their projects financed and constructed. This is due, in part, because of the impossibility of marketing bonds, particularly municipal bonds, even for economically justified projects, without guarantees for the debt from some organization recognized as financially acceptable by the financial community."

It warns that without such "standardized" terms the utilities will "negotiate" discounts from their actual costs.

The CEC's proposal is one of many conceivable financial arrangements which could assist development of qualifying facilities. The problem with adopting such a loan as part of the standard offer is that the risks associated with the loan guarantee will vary by project, making it impossible to fairly standardize terms. For this reason, we will not adopt the CEC's proposal as part of the standard offer, but rather allow such proposals to be negotiated as non-standard offers. With existing avoided costs offered as a foundation for negotiation between utilities and QFs, we believe these negotiations can be undertaken fairly.

d. Zero Capacity Payments

Staff raises the following issues in regard to zero capacity payments:

> "Do utility price offers which make no payment for capacity in the first few years of the 1980's reflect the ability of the utility to avoid costs? Are they reflective of the shorter lead times available with additions of capacity from OFs? Are they just and reasonable?"

Staff concludes that costs are actually avoided each year. Reasonable calculations of actual avoided cost would in-

clude the following: identified plant, reserves, power pool prices, shortage costs, opportunity costs, and replacement costs. Therefore, "capacity rates for purchase matrices will contain no zero values (rare instances excepted), or blank entries."

Edison agrees that rates for purchase of capacity should be based on "actual avoided costs", which:

> ". . . may result in zero capacity value during the initial implementation period of this OIR No. 2 due to prior planning commitments, as well as during some future situations when capacity purchases would be to the disadvantage of ratepayers."

It argues that short-term QF contracts are not conducive to the development of reliable and efficient generation resources and result in unnecessary risks. It suggests that staff ignores facts and asks: "How can the staff seek to require a capacity payment to a QF when the added capacity is of no value to the customer?" Zero capacity payments are alleged to be sometimes necessary to be fair to the ratepayer.

SDG&E agrees that "capacity benefits are never exactly zero." However, it relies on a quote from United States Supreme Court Chief Justice Warren Burger to support the proposition that such a determination is "of an adjudicative character" and can only be made in an evidentiary hearing.

PG&E supports the staff recommendation.

The issue of whether zero capacity payments are ever possible is better understood consistent with the distinction between short- and long-run marginal cost presented earlier. For short-run marginal cost, the capacity represents the costs associated with the possibility of a shortage. Insofar as an improved reserve margin always improves reliability at least to some degree, the capacity payment

always has some positive value. Assuming that the firm contracts offered by the utilities are tied with a utility's short-run energy cost (implying a short-run avoided cost concept) those contracts should always include a positive capacity payment though it may vary depending on the probability of a shortage. We conclude that a capacity value should exist for a one-year contract executed at the beginning of the year of delivery. This value should be the avoided (marginal) annual capacity cost based on the 1982 estimated cost of peaking capacity. This value should be available to QFs executing firm contracts on a $/kW and c/kWh basis similar to longer term contracts.

e. Refusal to Purchase

FERC regulation Section 292.304(f) provides, in part:

> "Periods during which purchases are not required.
>
> "(1) Any electric utility which gives notice pursuant to paragraph(f) (2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did make such purchases, but instead generated an equivalent amount of energy itself.
>
> "(2) Any electric utility seeking to invoke paragraph(f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility."

FERC states that this provision does not override "contractual or other legally enforceable obligations" of the utility to purchase from a QF and that such nonpurchase periods may be taken into account in setting rates for

purchases. There is widespread interest in the way this provision will be reflected in the standard offer.

Staff offers a series of recommendations. It proposes that utilities not be allowed to refuse to purchase energy or capacity which is fixed by contract over a duration of obligation, except for conditions of emergency, maintenance, or minimum load. As an alternative, staff suggests utilities may offer the actual lower avoided costs to QFs if actual avoided costs are lower than those sufficient for as-available deliveries. Under the alternative the utility must accept all deliveries tendered by the QF and offer the actual lower avoided cost. Utilities will be limited to 600 hours per year of paying a price lower than the published avoided cost price or refusing deliveries under conditions of maintenance or minimum load. Utilities that choose to pay lower prices would be required to pay prices higher than the published avoided cost price when actual avoided costs are higher than the published price for up to, but no more than, 600 hours per year.

Staff further recommends that utilities propose a notification procedure that will provide adequate notice to QFs of times of nonpurchase and prevailing prices. A list of periods of anticipated nonpurchase is suggested so that QFs would be able to schedule maintenance to coincide with such periods. A minimum of 48 hours notice is proposed for QFs with baseload or intermediate-type plants. A minimum of two hours notice is suggested for QFs with peaking-type plants.

Nonpurchases are proposed to occur in the following order of priority: first, small power producers who can inventory fuel; second, topping cycle cogenerators who can bypass the electric generation and save some fuel; third, bottoming cycle cogenerators and small power producers where fuel cannot be stored.

Staff further proposes that each utility be required to present a report in every ECAC proceeding explaining and

supporting periods when prices are lower than published or when nonpurchase occurs.

PG&E proposes:

"Utilities shall not be required to accept power from QFs during (1) emergencies; (2) times of pre-announced maintenance on the utility system which are limited to the shortest possible duration; and (3) operating conditions of minimum load on utility plants, the continued operation of which is necessary to serve anticipated daily load swings. Such minimum operating conditions include operation of geothermal facilities, utility dispatched hydro-electric facilities and firm purchases to obtain optimum use of these resources.

"To account for the availability of economy energy, which is energy purchased by the utility at a price below the Standard Offer published prices, utilities may either:

"a. Calculate their avoided energy cost to include an annually expected number of hours of economy energy. During periods when economy energy is available, the utility shall not refuse to accept QF energy deliveries based upon price; or

"b. Offer the lower avoided cost price to QFs when economy energy is available and only curtail, and not pay for, energy and As-Delivered Capacity (if the QF has chosen that option for capacity payment) made available by a QF which refuses to accept the lower price."

It would limit the number of hours of nonpurchase or lower prices to 600 per year.

PG&E also agrees that a report should be filed in ECAC proceedings (though not as detailed as proposed by staff)

and with staff's recommendations regarding notice to QFs and priority of refusal to purchase.

Edison states that it is concerned with the possible impact of paying published avoided costs to QFs when lower cost energy is available. It indicates that during such periods, the lower cost energy may be substantially below the cost of energy produced from the low sulfur fuel oil. It warns that a utility would be severely criticized if it were unable to meet its public utility obligation to its customers to provide lowest cost power, and an unjustified burden would be placed on the utility shareholder if the avoided cost payments were not recoverable in an ECAC proceeding. It concludes that payment at prices below published avoided cost, when its true avoided cost is less than the published price, is consistent with PURPA and FERC regulations.

SDG&E contends that "if the energy payment tables are properly calculated, the actual avoided costs to the QFs will be properly reflected and paid." It suggests that the problem of nonpurchase for economic reasons can be resolved through proper costing periods. By adopting a "super off-peak" reflecting anticipated periods of low cost energy, the times when avoided cost energy rates would be so far out of line with actual avoided costs to justify refusal of deliveries would be minimized.

SDG&E does support the ability to pay at less than published costs for certain maximum hours during the year, and accepts 600 hours as reasonable.

SDG&E states that staff's recommended notice requirement is "excessive". It offers two-hour notice for baseload and 30-minute notice for peaking units as "more realistic." It also objects to staff's nonpurhcase priority. It argues that "curtailments must be based only on size, from largest to smallest. In an operational emergency, it is impossible to spend time deciding who has fuel capabilities and who does not."

In general, we find that the utilities have interpreted this provision more liberally than apparently intended by FERC. The language of the regulation expressly limits its application to periods when the choice is between a QF and self-generation. There is no recognition of economy energy purchases.

This interpretation is supported by FERC comments:

> "This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when system demand later increased. As a result, the utility would be required to utilize less efficient, higher costs units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output."

This concern does not appear to contemplate economy energy purchases.

This issue must be addressed in the context of the standard offer options described above. The QF may contract to be paid on the basis of "the avoided cost calculated at the time of delivery." The right to not purchase arises only when that cost is less than zero, a negative avoided cost.

The QF may instead contract to be paid based on "the avoided costs calculated at the time the obligation is incurred." This method yields the sort of "published prices" apparently referred to in the various comments. There is no basis for refusing to purchase from such QFs merely because actual avoided costs occasionally go below pub-

lished prices. There is just as much of a chance that actual avoided costs will be occasionally higher than published prices. Allowing for nonpurchase in the first instance without providing for a higher payment when appropriate is unfair. Providing for both higher and lower payments is inconsistent with the purpose of the option to be paid based on avoided costs calculated at the time the obligation is incurred. Therefore this QF should be refused electric purchases only when the avoided cost is negative.

QFs have expressed concern that there may be no maximum number of hours during which refusal to purchase energy may occur. They feel this may result in financing problems (among other problems) since the utilities then are viewed as having an open ended opportunity to refuse purchases. A refusal to purchase would, of course, be subject to Commission review as provided by FERC. A more pragmatic method is require to allay these concerns. First, this decision will order that refusal to purchase, except in cases of emergency and scheduled maintenance, shall be limited to QFs of 1 MW or larger. Second, a refusal to purchase should only occur when a negative avoided cost occurs. Refusal to purchase should only apply in certain narrowly defined circumstances, unlikely to occur more than 100 hours per year.

Staff earlier recommended limiting the periods when a utility could pay a lower price or refuse to purchase to a time period "up to 600 hours" per year. Since the avoided cost price will reflected estimates of periods when avoided costs are higher or lower due to low load and high availability of hydro, periods need not be allowed during which a lower price is paid. In fact, FERC rules do not appear to allow utilities to pay a lower price during selected periods.

The earlier 600-hour limit stemmed from a PG&E estimate of the maximum number of hours in a high rainfall year that their hydro plants would otherwise need to be

curtailed and spill water. FERC rules require that the utility experience a negative avoided cost situation to permit nonpurchase. However, a negative cost would not occur when a utility curtails its own hydro. There remain few instances where negative costs would occur. For example, if a baseload or a large oil-fired intermediate load plant were shut down at night, due to an excess of QF electricity, but then could not be restarted and brought up to its rated output for the next day's peak load, and necessitated instead startup of a plant with very high generating costs (e.g., a gas turbine peaker or an expensive emergency purchase of capacity), the cost to meet the day's peak load might substantially exceed the avoided cost of the previous night's shutdown, thus giving a "negative avoided cost". A proper generating mix, including intermediate load plants of various sizes and possessing the ability to be throttled and even cycled should, in most cases, prevent occurrence of a negative avoided cost situation. It is recognized, however, that QFs need assurance at the outset of a reasonably small time period for nonpurchase. While no limit is specified herein, we do not think refusal periods, as defined, will be more than 100 hours per year and we will monitor utility actions.

FERC provides for effective notice to the QF so that the QF has ample time to cease delivery. In this respect we consider SDG&E's proposed two-hour notice to a baseload facility inadequate. The notice proposed by staff and PG&E is reasonably fair to the QF while remaining within the utility's planning horizon. No recovery will be allowed for payments resulting from insufficient notice unless the utility proves it was unable to provide greater notice, and that it attempted to make economy energy sales of the QF's power. We agree that QFs should be assigned priorities, in anticipation of the possibility that only partial restriction would occur. Staff and PG&E propose establishing priorities by technology. SDG&E proposes that size determine priority.

We are not persuaded by SDG&E's contention that it cannot consider fuel capabilities at the time of nonpurchase. We suggest that the time to consider such matters is during normal operating conditions when a priority scheme can be developed for later use. Refusal to purchase by size would be no more workable. The ability of the QF to function independently during times of nonpurchase is entirely the responsibility of the QF.

Thus we adopt staff's proposed priorities with modifications to reflect the more limited conditions we have established under which purchases may be refused. Specifically, while we recognize that an advanced notice of 48 hours for QFs with baseload or intermediate plants and two hours to QFs with peaking plants is a reasonable criterion there may be situations where 48 hours' advanced notice is not possible.

The notification procedure serves a second purpose. It also alerts the utility of a pending condition that should direct it to consider the opportunity to make economy energy sales. Before refusing to purchase from a QF, the utility should undertake to make such sales on behalf of the QF. We expect that the utility will undertake prudent planning to prevent negative avoided costs from occurring. The negative impact associated with the below minimum load condition suggests that prudent planning would entail arranging for economy energy sales as a margin of safety.

One distinction does arise between QFs for nonpurchase purposes, related to the particular form of standard offer. There is no capacity obligation during times of nonpurchase for as-available contracts. The obligation to pay for capacity during these times applies only to firm capacity contracts.

The orderly review of the application of these procedures requires that a report be filed by each utility in conjunction with its annual ECAC review. Utilities without ECAC proceedings will file an annual report no later than

each January 31 to cover the preceding calendar year. In this regard staff proposes that the report include at least the following:

a. The hours and duration of nonpurchase;

b. The amount of energy not purchased;

c. The utilities to which the electricity was offered for sale;

d. The prices at which the electricity was offered for sale;

e. The prices at which the neighboring utilities were willing to buy the electricity;

f. The QFs whose power the utility refused to purchase;

g. The lower prices offered to the QFs which the QFs refused;

h. A statement from each QF certifying the QF was notified within 48 hours for a baseload or intermediate QF and within two hours for a peaking QF, and that the QF actually refused the lower price;

i. The operating conditions under which the utility invoked the refusal to purchase and which required the refusal; and

j. A statement from each neighboring utility explaining their operating conditions at the time of the refusal to purchase which prevented them from taking the electricity at some mutually acceptable price.

PG&E and SDG&E object to various provisions as excessive and burdensome.

Paragraphs (h.) and (j.) do provide for information not in the control of the reporting utility. To that extent we

agree with PG&E and SDG&E that such information should not be required. In addition, ascertaining the exact amount of energy not purchased, as called for in Paragraph (b.), may prove difficult; therefore, estimates of these amounts will be sufficient. We also decline to adopt the staff's position which led to the recommendation contained in Paragraph (g.). However, the remaining items relate to data that is in the control of the utility and that should be gathered in the ordinary course of its business. There is no apparent hardship related to providing such information, at least during the early stages of QF development. We will require inclusion of these items in the annual reports. The report should also state the hours of advanced notification given each QF for each nonpurchase and, in cases where the prescribed minimum notice was not given, an explanation of why more extended notice could not be given.

f. Simultaneous Purchase and Sale

Simultaneous purchase and sale is a regulatory convention that allows a QF simultaneously to sell its own generation to the utility while purchasing its requirements from the utility. It is intended to respond to the situation where the retail rate is less than the avoided cost, by providing that the QF receives the full benefit of avoided cost pricing principles. The QF is not required to separate its load from its resources to qualify. The electricity flow is the same regardless. The difference is cash flow. Staff recommends that the QF have the opportunity to convert to and from simultaneous purchase and sale as it deems necessary, to protect itself from further regulatory and utility changes and future rate and tariff changes.

PG&E warns that indiscriminate switching between options by a QF will place unreasonable burdens on the utility. It agrees that the right to convert is reasonable if the following procedures are applied:

"1. The QF will be subject to the terms and conditions of all applicable filed tariffs and contracts in effect covering the existing and proposed facilities used to serve and/or interconnect the QF's project.

"2. The QF will be required to reimburse the utility its out-of-pocket costs, with appropriate credits, resulting from any change in the utility's facilities required to accommodate the QF's change in sales option. Increased or decreased interconnection and service facilities will usually require new agreements and result in an adjustment of charges to the QF to meet such new requirements. Where the QF's switching of sales options will render the utility's facilities idle in whole or in part, the QF may elect to do one of the following: (1) pay the utility to rearrange its facilities to meet the new and reduced requirements, or (2) with the utility's approval, pay the utility to reserve any excess capacity in its facilities. Such charges will be in addition to any other utility charges applicable to the QF's new service requirements.

"3. The QF will provide the utility with reasonable and appropriate notice of its new requirements brought about by any switching in sales options in order to allow the utility adequate time to accommodate the QF's request."

It provides an example that illustrates its proposal.

SDG&E agrees that simultaneous purchase and sale is a required option, but takes a much less flexible view regarding switching. It proposes that the QF make the election at the time the contract is made and that no switching be allowed. It argues:

> "If no election were required at the one time of execution the utility would be unable to forecast sales and revenues in a general rate application. It seems unlikely that a filing which contains substantial sales variances depending on how the final revenue is allocated, would be acceptable to the Commission.
>
> "A failure to make such a firm election would also allow any QF to at least partially thwart Commission policy being implemented in these rates. For example, had this policy been in effect when the Commission ordered implementation of Time-of-Use rates, the QF could have avoided such rates by ceasing to sell and using its own generation. SDG&E supports the position that any customer can avoid Commission policy by generating for his own use. However, a QF who wants to take advantage of Commission purchase policy through simultaneous purchase and sale should be subject to Commission policy on the sale side as well."

It contends that allowing the QF to switch results in an unreasonable burden on other ratepayers and the utility.

We agree with the staff in principle that the QF should be able to convert to and from simultaneous purchase and sale unless the QF has selected forecasted or levelized energy payments under a long-term contract. In such cases, the QF must commit its entire output to the utility. Conversions should be limited to once per year as is currently the practice under Rule 12 for changing rate schedules.

We agree with PG&E that in practice the conversion must be conditioned on reasonable notice and full compensation. Notice requirements should not be excessive. However, if the interconnection and metering installed for selling surplus power are not compatible with simultaneous

purchase and sale, a longer delay may be necessary for conversion. The QF may also encounter additional interconnection costs if conversion of the original wiring and metering is required. The QF that pays for a more costly interconnection and metering arrangements under simultaneous purchase and sale and then converts to selling surplus power would not be able to recover the additional costs except in terms of a salvage cost. The QF that receives capacity payments under simultaneous purchase and sale through a long-term contract and converts to sell surplus will face termination provisions.

g. Exceptions

The foregoing discussion addresses the matter of the terms of the standard offer to be applied to facilities of more than 100 kW. There remains the matter of how these principles will apply to Sierra and Pacific Power & Light company (PP&L).

We discussed earlier Sierra's concern that QF production causes certain potential problems because of its size, location, and configuration. We consider the import of its position to be that its actual avoided costs are susceptible to substantial fluctuations depending on the number and size of prospective QFs. This problem is best resolved by excusing Sierra from the obligation to provide a standard offer to QFs of more than 100 kW. Instead, Sierra will be allowed to contract with each on a nonstandard basis that reflects the actual costs avoided by each QF consistent with the avoided cost principles in this decision.

PP&L asks for some from of exclusion or waiver from some portions of the final staff report and this decision. It contends that PP&L is "entirely unlike the model utility that is assumed to exist in the staff's final report." It argues that "the utility assumed to exist is an oil-fired geographically centralized utility, one that uses oil as a primary source of energy, one that serves a relatively

centralized and contiguous territory." It cites a number of factors that distinguish it from the others.

We agree that PP&L is different in material respects. We therefore order the utility to propose a standard offer for review by parties based on its avoided costs. We will determine what additional action to take after reviewing its filing. We will not order the utility to adopt the specific standard offers filed in this decision at this time.

3. Standard Rates For 100 Kilowatts or Less

FERC Regulation Section 292.304(c)(1) provides:

> "There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 10 kilowatts or less."

Such standard rates must be consistent with the specified factors affecting rates for purchases and may differentiate among QFs on the basis of technologies.

Staff recommends that standard rates for QFs of 100 kW or less should be simple, paying for both energy and capacity in cents per kWh. Staff proposes that the rates be either time or non-time differentiated, at the QF's option. As with the larger QFs, staff suggests that the capacity payment be based on an aggregate capacity contribution of 50% of the full 25-30 year avoided capacity cost at a 100% capacity factor, regardless of technology. Transmission and distribution avoided costs and losses would be paid to QFs choosing simultaneous purchase and sale.

The utilities respond in much the same terms as with regard to the standard offer issues related to larger QFs. PG&E proposes that the capacity component of the prices should be based on an aggregate capacity contribution of 35% (as opposed to 50%) of the full one-year avoided capacity cost. SDG&E does not agree that the capacity por-

tion of the rate should be paid on a cents per kWh basis for both time and non-time differentiated deliveries. It objects to any capacity payment method that makes substantial payments on a non-time differentiated basis. It characterizes staff's proposed 50% value as an arbitrary gratuity at the expense of the ratepayers. Edison complains that staff's recommendations reflect staff's improper attitude toward the avoided cost concept. Edison repeats its contention that costs cannot be deemed to be avoided.

We agree that the standard rate for small QFs should be simple. We adopt staff's recommendation that the payment for energy and capacity be expressed in terms of cents per kWh and be offered on either a time- or nontime-differentiated basis. In the context of this proceeding, this result is best achieved by a payment equal to the standard rate calculated for large QFs providing as-available energy as provided for above.

Our "as-available" offer for large facilities is on a time-differentiated basis, to reflect the fact that capacity is more valuable during peak periods than during other periods. In the event a qualifying facility less than 100 kW chooses not to buy a time-differentiated meter, the price incentive to be available during periods when capacity is most needed will be reduced. Consequently, utilities may propose capacity payments for qualifying facilities without time-of-use meters that aggregate over a year to 50% of the capacity for those with time-of-use meters.

Larger QFs will receive regular service from a utility under the applicable filed tariff schedule, standby service under a standby tariff, and parallel generation interconnection under either a parallel generation tariff or a standby tariff. Power will be purchased by the utility under a contract based on either the standard price offer or a negotiated pricing arrangement. For small QFs under 100 kW (and even for larger QFs if the utilities deem it feasible to do so), simplified service arrangements are necessary.

This should be accomplished by tariffs which cover services supplied by the utility, including parallel generation interconnection, and provide for simplified agreement forms.

These simplified tariffs will be based on the standard price offer and will not preclude small QFs from choosing options available under the standard price offer which may not be contained in the simplified tariffs. An example could be the option of simultaneous purchase and sale which would require additional metering and contract terms not provided for under the tariff offerings for small QFs.

The tariffs governing sales by QFs to utilities are in some respects conceptually different from usual tariffs which cover the terms and prices of services provided by the utility. Because of this difference, certain aspects of our General Order 96-A should not apply to the tariffs covering the QFs' sales to utilities (as opposed to tariffs setting forth the services provided by the utility to the QF and technical arrangements, such as interconnection requirements). First, any contracts authorized by these tariffs need not contain the contract provisions required in Section IX of General Order 96-A. Second, the provisions of Section X, concerning contracts and services at other than filed tariff schedules, should not apply to contracts differing from the terms of the simplified tariffs. The discussion of nonstandard contracts in the following pages also applies to deviations from the tariffs governing the QFs' sales to utilities.

D. Nonstandard Contracts

1. In General

We have provided for a "standard offer" that is intended to be widely applicable to QFs of diverse characteristics and to effectively promote cogeneration and small power production. The more generally suitable the standard offer, the less need for parties to negotiate nonstandard contracts.

Nevertheless, there remains the likelihood that nonstandard contracts will be necessary. The range of possible conditions that might lead to such contracts is too broad to support more than idle speculation. The object of negotiations is to produce a contract that is the economic equivalent of the standard offer.

We indicated above that payments under the standard offer are deemed reasonable and are recovered through ECAC. Payments pursuant to nonstandard contracts are recoverable through ECAC upon a showing of the reasonableness of such payments. This differing ratemaking treatment leads to one of the major issues in this proceeding - whether this Commission should devise a procedure for reviewing the reasonableness of nonstandard contracts in advance of their effectiveness. This issue is discussed below.

Another issue that concerns many parties is the prospect of protracted negotiations over contract terms. Several parties have proposed specific schedules for offers and replies, intended to alleviate this problem. This issue is also discussed below.

2. Advance Approval

Staff observes that uncertainties associated with nonstandard contracts might delay the development of cogeneration and small power production.

> "For example, utilities might hesitate to sign contracts containing price terms other than those approved in advance by the Commission, for fear that such price terms would be considered not 'sufficient to encourage cogeneration and small power production' (Section 292.304(b) (3)), or that payments made for power purchased under nonstandard contracts would not be fully recovered."

Although advance review by the Commission of nonstandard contracts might help to reduce uncertainty, staff rec-

ommends that the Commission not give advance review and approval. It recommends that review be limited to ECAC proceedings.

Staff warns that advance review might actually delay development, contrary to its intended purpose. The procedure might take months, with the prospect of a longer process if any party petitions for rehearing or petitions the Supreme Court for review. Any decision other than unconditional approval might require further negotiations, delaying the contract. The possibility of Commission review might cause the parties to rely less on their own bargaining skills and more on the judgment of the Commission.

Staff is uncertain regarding the exact nature of review anticipated.

> "If the Commission is reviewing executed contracts, such review would appear to be superfluous, because in that case the utility and the QF would have already freely agreed to a mutually satisfactory arrangement. Review for fairness to ratepayers would occur, as with other utility contracts for the purchase of energy or fuel, in the utility's general rate case or ECAC proceeding. If, on the other hand, the Commission is asked to review proposed contractual terms, the Commission runs the risk of inserting itself in the midst of contract negotiations or of becoming an arbitrator of the parties' differences. It would be inappropriate for the Commission to become an active participant in negotiations involving a utility which is subject to the Commission's regulation and a QF which is not directly under the Commission's jurisdiction and which has been specifically exempted from state regulation (§ 292.602(c))."

Staff is concerned that the QF would not want to disclose the information that would be necessary for effective arbitration.

Further, staff states that even the most cursory forms of advance review would require considerable time of the staff and Commission. Reviewing all nonstandard contracts, including those which vary only slightly from the standard offer, would be unnecessary and inefficient, but staff doubts whether effective guidelines could be devise that could distinguish between minor and major variations.

Staff observes that the purchasing utility does assume a risk by proceeding without prior Commission approval. It suggests that the Commission should clearly state that utilities are expected to assume some risk in contracting with QFs and urges that the Commission look favorably on a utility that willingly assumes such risk.

Staff recognizes the interest of many parties in having a procedure for advance review. It proposes such a procedure for comment though its recommendation is that no such procedure be adopted. The essence of its proposal is that either a utility or a QF may submit a "Request for Review" of a specific contract provision. The Commission may accept the matter for review, in which case, an application shall be filed. The Commission decision may be deemed precedential as regards similar provisions in similar contracts.

The utilities and many interested parties urge the Commission to undertake advance review. Both legal and policy arguments are offered in support of this position.

PG&E argues that Public Utilities (PU) Code Section 2821 requires the Commission to approve the payment terms of nonstandard contracts prospectively, referring to the following portion of the statute:

> "The Commission shall approve and establish equitable charges to be paid by an electrical cor-

> poration which purchases electricity from any private energy producer employing other than a conventional power source for the generation of electricity. . . ."

PG&E contends that the use of the words "to establish" and "to be paid" in the statute require that the Commission act prospectively. PG&E expects that as precedents are declared, only those contracts that deviate substantially from the standard offer or from those contracts previously reviewed will be submitted for review. PG&E predicts that review will be infrequent.

As a policy matter, PG&E argues that even if advance review is not required by statute, staff's proposal to deny advance review would deter QF development. Under such circumstances utilities will include a provision in all nonstandard contracts allowing the utility to adjust the contract to the terms and conditions subsequently approved by the Commission, and recover all payments in excess of those subsequently authorized. In such circumstances the QFs would have no certainty and the purpose of nonstandard contracts would be defeated.

PG&E is not persuaded by staff's warning that the review procedure might take months. PG&E argues that the time required of the Commission and the staff will not be conserved by postponing review until ECAC proceedings, since the same review is required before or after the effective date of the contract.

Edison contends that the Commission should review and approve or disapprove all nonstandard contracts between utilities and QFs prior to such contracts' becoming effective, whenever the price paid exceeds the utility's avoided cost.

> "In those rare instances where the overall benefits of a transaction, such as demonstrating a

> new technology, appear to justify the payment by a utility of a price in excess of its avoided cost, the Commission should review and either approve or disapprove the contract prior to its becoming effective. The Commission's review burden would be small under this approach because the utility will seldom wish to pay more than it can be compelled to pay. If the transaction appears to be truly beneficial, overall, the utility should not be subjected to second guessing by the Commission in a subsequent proceeding."

Edison suggests that there is no need for the Commission to review nonstandard contracts where the utility pays less than avoided costs.

Edison proposes that General Order 96-A, Section X should be amended. That section requires that no utility shall make any contract that deviates from its filed tariffs without Commission authorization. Edison suggests that amendment is required to remove uncertainty and ambiguity regarding whether that provision applies to purchases by a QF.

SDG&E believes that nonstandard contracts can perform an important function in promoting cogeneration and small power production. SDG&E warns that such contracts may at times exceed avoided costs and at times fall below avoided costs.

> "For this reason, the proposal made by Southern California Edison that only nonstandard contracts which exceed avoided costs should be subject to PUC approval is incomplete. SDG&E would suggest rather that the Commission only approve contracts upon which the QF and the utility have agreed but which they have not yet executed. The PUC's approval should be limited to the rate

> itself and the recoverability of that rate by the utility."

SDG&E foresees that eventually there will develop "a uniform nonstandard contract rate which many parties could utilize."

SDG&E contends that policy and legal considerations require advance approval. Regarding policy, it states that staff misunderstands the character of purchased power contracts that are not subject to Commission approval:

> "Since the majority of such purchased power contracts has (sic) already been determined by the FERC to be reasonable, the utilities are not nearly as vulnerable to an adverse PUC determination as Staff would suggest. Most purchased power contracts are not like ordinary commercial agreements in that regard."

SDG&E points to its Heber Binary Project and the Magma Niland Geothermal purchased power contract as examples of prior approval entertained by this Commission.

SDG&E argues that the Commission should provide for advance review as a matter of simple fairness, referring to the prospect of a rate of return penalty if the terms of its contract are not sufficiently fair to the QF, or having expenses disallowed in an ECAC proceeding if the payments are too high.

SDG&E makes the same legal argument advanced by PG&E - that PU Code Section 2821 requires advance approval. SDG&E contends that while this proceeding may constitute sufficient review of utility standard offers, it is clearly not sufficient for nonstandard contracts "since these contracts are not the subject matter of this proceeding." SDG&E suggests that staff's concern that the Commission might end up in the role of an arbitrator is resolved "by simply requiring that the parties agree in the first place

as to the terms of the contract before it is submitted to the PUC for approval."

SDG&E concludes that "if the PUC will not grant prior approval to the nonstandard contracts, the utility must protect itself in some form." SDG&E anticipates that it would react similarly to the manner described by PG&E - inserting into the contract a provision that payments are subject to modification upon an adverse determination by this Commission and that overpayments would be recovered from the QF. The resulting uncertainty would discourage QF development. SDG&E urges this Commission to reaffirm its commitment to cogeneration by approving a procedure for prior approval of nonstandard contracts.

CEC supports the utility position. It contends that prior review will be essential to QF financing efforts.

> "This conclusion is based upon a clause which each of the utilities have placed in their contracts, which states in effect, that the contracts shall not be effective until the Commission has approved each and every term and condition of the contract. The net effect of this kind of clause is to mandate renegotiation of the contract should the Public Utilities Commission say no to any term or condition."

Union asserts that PURPA and the FERC regulations were intended to eliminate this regulatory barrier and to allow industry to negotiate freely with utilities. Union contends:

> "Prior review would not only carry the onus of regulation where none is warranted, it would also be time-consuming and costly. It would tend to discourage rather than encourage industry seeking contracts to sell power. In addition, it would require direct intervention of the Commission in what would ordinarily be private negotiations be-

> tween two (or more) business interests. This would have the appearance as well as the indirect effect of, further regulation, even apart from the ECAC and general rate proceedings."

Union goes so far as to suggest that review and approval of contracts by the Commission and the indirect terms and conditions of these contracts through the device of after-the-fact refusal to allow recovery of costs in ECAC or general rate cases is an unwarranted inhibition to the further development of cogeneration.

Pan Aero and Transition Energy Projects Institute (TEPI) also oppose advance review. TEPI suggests that if advance review is adopted, that only concluded contracts be submitted unless there are irreconcilable differences requiring Commission review.

Discussion

The threshold question is the legal question. After consideration of the authorities cited, we conclude that we are not legally compelled to provide for advance review of nonstandard contracts.

As indicated, several parties argue that advance review is required by PU Code Section 2821. We find this argument without legal merit.

PU Code Section 2821 does provide that this Commission "shall approve and establish equitable charges . . . on its own motion or on application of an electrical corporation or a private energy producer." We consider this mandate to be no more than a direction that we provide for a "standard offer". We conclude that by this decision we are acting on our own motion to "approve and establish equitable changes." We find no additional burden to entertain applications on behalf of parties that are not satisfied with the "equitable charges" established by this Commission.

We also seriously doubt whether PU Code Section 2821 would provide the procedural vehicle intended by the par-

ties. In general, these parties seem to have in mind a procedure whereby an executed contract is proffered for approval or disapproval. But if we assert jurisdiction under PU Code Section 2821, our authority would be to "approve and *establish*" charges to be paid under a nonstandard contract. Thus, we would have jurisdiction to substitute our own judgment and to modify the contract accordingly. This is certainly not the process intended by the parties.

We are also not persuaded that General Order 96-A has any relevance to this issue, except as an argument by analogy. On its face it applies to utility sales to customers, not to utility purchases that may be from customers.

While we do not find ourselves legally obligated to provide advance review of nonstandard contracts, we have decided to provide such review for applications filed during the next two years. Both utilities and QFs argue that advance review of nonstandard contracts may in some cases be necessary. We are persuaded that without advance approvals, creative nonstandard offers could be stymied and that QF development would thereby suffer.

The nonstandard contracts we anticipate generally involve some sort of debt guarantee, levelized payment or payment floor which reduces risks for QFs and places those risks upon ratepayers. In return for taking such risks, ratepayers are afforded some reduction on avoided cost payments. Given current ratemaking treatment for costs associated with QF purchases, utilities are intermediaries in the transaction as costs are flowed through ECAC. In the case of standard offers, utilities are secure that payments to QFs will be recovered. With *nonstandard* offers, the utility has no such assurance unless advance review is permitted. Without advance review, a utility risks being found imprudent for nonstandard contract payments; a potential cost for which the utility has no compensatory benefit. Under the circumstances, a utility is likely to choose not to write nonstandard contracts at all, or to include in

such contracts a provision to void the agreement if an associated expense is disallowed by this Commission, or to demand such concessions from QFs beyond the standard avoided cost offer that QFs are discouraged from departing from standard offers at all.

The issue, then, is whether we wish such nonstandard contracts to be written. It is not necessarily clear that we do. In adopting standard offers, we are presenting our conclusion on what is an appropriate payment for electricity provided by a QF. We believe our standard offer is a fair price for ratepayers, and provides an excellent opportunity for QFs to prosper. We would expect most parties to find such an offer satisfactory, and that special financing or other measures to reduce risk be sought from financial or other institutions.

While we believe that the standard offer should be satisfactory generally, we can envision some cases in which nonstandard treatment would benefit both the QF and ratepayers. Especially as the QF market is developing, and before financial and other institutions understand its nature, some QFs may wish to seek alternatives to reduce risk. For example, the agreement SDG&E recently reached with Kelco to provide a floor on avoided cost in return for a reduction in payment appears to be desirable to all parties, including ratepayers. We can imagine other such contracts which benefit ratepayers. We will entertain such applications within the guidelines established.

The guiding principle for nonstandard contracts upon which publications should be based is that the contract terms, taking into account the associated risks, should not be more than expected avoided costs under the standard offer. Ratepayers are expected in most non-standard offers to accept some technological or market risk, in which ratepayers should be returned compensating benefit. Applications for nonstandard contacts should clearly state all the differences between the contract and the standard of-

fer, and identify all gains and costs for ratepayers. The application should further demonstrate why ratepayers should either be indifferent to or prefer the nonstandard contract over the standard contract. In the rare event that the nonstandard offer is above avoided costs an explanation of how ratepayers otherwise benefit should be presented. In all cases, the burden is on the applicant to demonstrate why the nonstandard offer is in the ratepayers' interest. We must caution all parties that the Commission will review these contract as a banker reviews a loan application, with scrutiny and skepticism. While we want to encourage QF development, we do not wish to burden ratepayers in the process.

In terms of procedure, we will allow utilities to file nonstandard offers for review. We ask that utilities submit only those offers for which the utility has significant questions about whether we would find the offer prudent. Once the Commission has reviewed and expressed its opinion as to the consistency of a contract price and terms with avoided cost principles, utilities should be expected to use these principles to sign similar contracts without review. We will attempt to handle applications for projects less than 10 MW through ex parte procedures. Applications over 10 MW will generally require hearings. Exceptions may be made depending upon the novelty of a particular application, or the degree of ratepayers' exposure.

The staff shall review applications for approval of nonstandard contracts expeditiously and where hearings are necessary, they shall be set promptly. If the staff finds that staff review cannot be completed and hearings begun within 45 days because of the workload of other matters pending before the Commission, the Executive Director shall report this to the commission, which may then reorder work priorities to resolve related issues promptly.

Our staff makes strong arguments in this proceeding against advance approval. It argues advance approval could

lead to delay of projects, and to direct involvement of this Commission in the negotiations with QFs. On the first point, we acknowledge that review of contracts may be time-consuming. It is for this reason that we ask that QFs generally seek financial support through other institutions, not through nonstandard offers. At least while the market is developing, however, we see merit in permitting some nonstandard contracts even though such review will be time-consuming. We would prefer to have good projects somewhat delayed than not constructed at all.

Finally, on the issue of PUC involvement in negotiating nonstandard offers, we do not believe it will be necessary or appropriate to become involved. Utilities and QFs are to negotiate with each other, and we will review the product for approval or disapproval. We have no intention of intervening or rewriting contracts.

To assure review of this procedure after we have had experience with it, we will establish a sunset provision. Unless we make an affirmative decision to reinstate our procedure, we will not consider applications for prior approval of nonstandard contracts filed two years after the effective date of this decision.

3. Negotiations

Staff states the obvious: "Utilities are expected to negotiate in good faith with QFs." Staff proposes certain guidelines that are intended to provide a standard:

> "A utility must respond specifically to proposals of a QF within 60 days of the receipt of the QF's initial contract proposal and within 30 days of the receipt of subsequent proposals related to the initial proposal. Rejection of a QF's proposal shall be accompanied by a specific counter-offer concerning the subject matter of the QF's proposal. If the utility is unable to respond to the QF's proposal within 30 days, it shall inform the QF of

(1) the specific information needed to evaluate the proposal, (2) the precise difficulty encountered in evaluating the proposal, and (3) the estimated date when it will respond to the proposal."

Other parties respond with schedules of their own.

We are not sure that the give and take of contract negotiations can be reduced to a formal schedule. We are not inclined to require such a procedure without a more convincing argument that it is necessary, or likely to be successful. Enforcement would require the parties to conduct their affairs in an overly rigid fashion. For example, the QF's "initial contract proposal" might evolve, rather than simply appear. We would rather not have to decide which was the day the proposal was complete, or whether the utility's estimated time for response is reasonable.

Nevertheless, we recognize that staff has addressed an important problem. Protracted negotiations that lead nowhere are exactly what this regulatory scheme is intended to avoid. The utilities are expected and shall be required to bargain conscientiously toward a conclusion. The best evidence of good faith is a collection of written documentation compiled along the way. When the utility is unwilling or unable to accept a QF's proposal, the utility must respond with a timely counteroffer, or an explanation (as proposed by the staff) of:

1. The specific information needed to evaluate the proposal;

2. The precise difficulty encountered in evaluating the proposal; and

3. The estimated date when it will respond to the proposal.

The Commission will entertain formal complaints raised by QFs who can demonstrate that the utility has failed to bargain in good faith. Such complaints from QF's shall be

treated expeditiously by the staff, and where hearings are necessary, hearings shall be set promptly. If the staff believes that QF complaints cannot be resolved quickly because of the workload of other matters pending before the Commission, the Executive Director shall report this to the Commission so that the Commission can assign priorities to these matters and resolve the QF complaints as quickly as possible. A utility found not to have bargained in good faith will stand in violation of this order and will be open to potential punitive action by this Commission.

We are also concerned that QFs considering a negotiated contract are not fully aware of their rights to request a contract under the terms of the standard price offer. Should the QF propose prices or terms outside the standard price offer, we will expect the utility to advise the QF that the contract discussions are proceeding on a negotiated basis, distinct from the standard contract, before responding with a nonstandard contract. The notice shall include a summary of terms available under the standard offer, and an offer to enter into a standard offer contract. Likewise, if the utility initiates a nonstandard contract with its attendant price offering, the utility will be expected at the same time to present to the QF the standard offer.

4. Contract Renegotiation Provision

We are concerned about the utility-proposed renegotiation contract term which would allow the utility to modify a signed contract retroactively (and prospectively) in the event any provision is found unreasonable in the future. Such a term would apparently destroy the certainty that financial institutions require for their participation. We find that such a term should not appear in standard offers. A contract term which would allow the utility to modify a signed contract retroactively and prospectively in the event any provision of the contract term is later found unreasonable is not a reasonable term in a standard offer contract.

V. Wheeling

FERC regulation Section 292.306(d) provides for limited wheeling:

> "If a qualifying facility agrees, and electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e) (4) and shall not include any charges for transmission."

In its comments FERC indicates that there are several circumstances in which a QF might prefer that an electric utility with which the purchasing utility is interconnected would make such a purchase - for example, if the avoided costs of the second utility are higher. However, if the first utility does not agree to transmit the purchased energy or capacity, it is not forced to wheel and retains the purchase obligation.

Staff states that the extent of state authority to order wheeling is limited by federal law by virtue of the preemption doctrine. It points to PU Code Sections 2801-2816 as providing this Commission with limited jurisdiction to order interconnection for the purpose of transmitting energy on behalf of a "private energy producer," assuming that certain specified findings are made. Staff argues that these sections avoid federal preemption because jurisdiction is limited to transmission for the private energy producer's own use and because the transmission is limited to the service area of a single utility. Staff concludes that, although the Commission

has no authority to require wheeling when federal jurisdiction attaches, utilities should be urged to consider wheeling requests on a case-by-case basis.

The utility response is varied. PG&E states that staff's position agrees with its view. Edison argues that even transmission on behalf of a private energy producer is subject to exclusive federal jurisdiction through application of the commingling doctrine. SDG&E focuses on conditions that it proposes to require in the event that QF generation is made available by a wheeling utility.

CEC contends that this Commission should state clearly that utilities are encouraged to wheel. It states that this Commission can and should use our authority to ensure that utilities do not use their monopoly control over transmission lines to hinder QF production. It offers the following statement for our endorsement:

> "The Commission will not tolerate the utilities' use of their control over the transmission system to limit access by small power producers who seek to use the transmission lines to transmit power to a purchaser of the small power producers' energy. Such actions will be considered by the Commission in setting rates for utilities in future ratemaking proceedings, and in evaluating the utilities' imagination and vigor in implementing and pursuing conservation and the development of small power production and renewables."

CEC suggests each utility report regarding requests for transmission service as part of its rate case showing.

Union states that wheeling can be a major factor in promoting cogeneration and small power production. It urges this Commission to strongly encourage utilities to consider all requests to transmit power and to accommodate such requests on a fair and nondiscriminatory ba-

sis. It warns that otherwise even such large companies as Union may be discouraged from pursuing opportunities.

NRDC argues that staff's conclusion regarding the extent of our jurisdiction is based on an unnecessarily narrow view of wheeling issues. It recommends that we consider fashioning "narrowly tailored wheeling requirements to further the objectives of PURPA."

CMA addresses specifically the issue of wheeling between two facilities of the same industrial entity. It argues that the principle of simultaneous purchase and sale fundamentally changes the concept of wheeling. It contends that the principle applies whether the resources and load are on the same site or separate sites. CMA observes that the utilities readily accept the same site principle, but reject its extension to separate sites.

We agree that wheeling is an important concept that can make a material contribution to cogeneration and small power production in California. For that reason we state plainly that each utility's willingness to wheel will be examined in the context of its overall conservation activities in conjunction with general rate case proceedings.

Regardless of a utility's willingness to wheel power for its neighbor, each utility, for some reason, appears to limit its cogeneration and small power activities to the confines of its own service territory. This occurs even though locally available generation may not match requirements. Further, some generating sites, while located in other service territories, may still be closer to the buying utility's load center than would alternatives such as out-of-state power purchases. We find that it is not prudent for a utility to fail to pursue an otherwise beneficial facility simply because it is located in another service territory. In addition, this Commission will view with disfavor any actions or inactions by a utility which will interfere with the signing of a contract between a neighboring utility and a cogenerator or small power producer located in its service territory.

In the discussion above we considered whether to limit utility recovery in cases of utility participation in successful cogeneration and small power production ventures. We indicated that such participation should be favored. In relation to wheeling this principle applies to the prospect that a major facility may require utility financing or guarantees in order to be built (a classic "nonstandard" contract) that the "host" utility is unwilling or unable to provide (for example, the utility may already have excess capacity). In this case another utility may be able to participate under terms and conditions that benefit all parties.

The attractive feature of wheeling is that it introduces actual competition into the market. To the extent that competition occurs, the burden of regulation is proportionately reduced.

Respondent utilities are required to buy energy and capacity from a QF located in the service area of another utility whenever the conditions of Subsection 292.303(d) of the FERC rules are met.

Subsection 292.303(d) is clear that the price paid to the QF by the purchasing utility shall not include any charge for transmission but may be either raised or lowered to reflect the savings or costs resulting from line losses. The discussion accompanying the final FERC rules indicates that the serving utility would collect any applicable transmission charges for wheeling power from the QF and that, in the case of respondent utilities, the rates for these charges would be set under Part II of the Federal Power Act. Transmission charges by the serving utility should take into consideration the extent to which the QF's power displaces power that would otherwise be transmitted from the utility which receives the QF's power to the serving utility. For example, if all of the QF's power displaces power that would otherwise be delivered by the purchasing utility to the serving utility, the transaction becomes a

bookkeeping rather than a physical exchange, and therefore no transmission charges would appear to be justified.

At this stage of this proceeding we are optimistic that the respondent utilities subject to this Commission's jurisdiction will respond to wheeling requests in a fair and nondiscriminatory manner. If our optimism is well-founded, we will need not decide the extent of action needed to encourage wheeling. If our optimism is unfounded, we will take what ever action is appropriate.

In this posture we must necessarily require information to be provided periodically regarding utility actions in this regard. Therefore, we will require each utility to report at the end of January of each year on wheeling performed during the previous year, the parties for whom the wheeling was performed, the terms and conditions applied to the transaction, the technical wheeling arrangements, the status of any pending requests to wheel, and the circumstances relating to any request that was refused.

VI. Rates for Sales to QFs

A. Introduction

FERC Regulation Section 292.305 provides that rates for sales to QFs shall be just and reasonable, in the public interest, and shall not discriminate against any QF in comparison to rates for sales to other customers served by the electric utility. Rates based on accurate data and consistent systemwide costing principles are deemed not to discriminate, to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics. Upon request of a QF, each utility must provide:

1. Supplementary power,
2. Backup power,
3. Maintenance power, and
4. Interruptible power.

The appropriate state regulatory agency may waive the requirements upon a finding that compliance would impair the utility's ability to render adequate service to its customers, or place an undue burden on the utility. The regulation expressly provides that the rate for sales of backup or maintenance power should not be based upon an assumption that forced outages or other reductions in output will occur simultaneously, or during system peaks, or both, and shall take into account the extent to which scheduled outages of the QF can be usefully coordinated with the utility's own scheduled outages.

B. Supplementary Power

Supplementary power is electric energy or capacity used by a facility in addition to that which it ordinarily generates on its own. The concept is not applicable when simultaneous purchase and sale is elected, as the QF is supplied all of its requirements by the serving utility.

Staff states that QFs are now furnished supplementary power under regularly filed tariffs applicable to all customers of the same class as the particular QF. Staff contends that such service does not involve costs that differ from costs to serve other customers. It finds that present practice reasonable and recommends that it continue. No party objects to this recommendation.

C. Backup Power

Backup power is electric energy or capacity available to replace energy generated by a facility's own generation equipment during an unscheduled outage. Again, the concept does not apply when simultaneous purchase and sale is elected.

Staff argues that there is a significant cost to a utility to provide backup power to a QF that is not recovered through energy rates charged for supplementary power and not reflected in avoided cost payments. Staff contends

that reasonable standby rates, based on the utility's cost of providing backup power, should be charged to QFs.

Staff states that:

> "Standby rates as now filed by PG&E, SCE and SDG&E are designed to recover the utility's cost of providing only a fraction of a MW of backup generation costs together with transmission and distribution costs. . . . Standby rates, by themselves, do not recover the utility's cost of providing backup power. The rates were set so that the standby charges combined with the recovery of demand charges through regularly filed tariffs in those months in which the QF requires backup power would recover the utility's costs."

Staff asserts these rates are consistent with the FERC requirement that such rates not be based on the assumption that all QFs will fail simultaneously. Staff recommends that this Commission not adopt a formula for developing standby rates. Existing rates are allegedly below rates that would result from such a formula. Staff suggests that the Commission accept existing basic standby rate levels in dollars per kW per month as reasonable and allow rates to increase in general rate cases in proportion to increases in per kW capacity costs.

Staff recommends no standby rates for QFs not now served by rate schedules with demand schedules. Standby rates for new technologies such as photovoltaics should not be finalized at this time. Appropriate rates could be developed as data on the technology becomes more refined.

Staff recommends that all utilities develop and file alternative standby rates for QFs on time-of-use rates. These rates should be similar to Schedule SCG-2 of Edison. A three-month ratchet, including the month of occurrence, is recommended. The ratchet would not exceed 90% of the demand in the month of occurrence and would be extended

by three more months for each additional occurrence, but not to exceed 12 months. Staff recommends that PG&E, with no ratchet provision in its present time-of-use tariffs, should develop and propose an appropriate alternative standby rate.

Staff further recommends that standby charges should be waived for any QF that attains an 85% capacity factor without downtime during on-peak periods, excluding scheduled maintenance, in any month. This waiver is in recognition of the lower cost to serve QFs that operate with high reliability.

Staff also proposes that standby rates be made available to self-generators used to reduce peak demand. Staff states that such rates are appropriately higher than rates to QFs, "in recognition of the lesser value of self-generation to the utility." Self-generators reduce the utility's peak demand but do not conserve energy through enhanced efficiency or fossil fuels as compared to a cogeneration or small power production facility.

PG&E does not have a ratchet provision in its present time-of-use tariffs. PG&E opposes staff's proposal that it develop such provisions as part of "an appropriate alternative standby rate." It states that its present schedule offers low standby rates to both large and small cogenerators.

> "This schedule does not burden a QF with disproportionately higher standby charges if the size of the cogeneration facility is larger than 40 percent of the load."

PG&E asks to be excused from filing the proposed rate.

PG&E disagrees with staff's proposed waiver of standby costs where the QF attains an 85% capacity factor in any particular month. PG&E claims that attempts to comply would be difficult because a utility does not ordinarily meter cogeneration production and would have no basis for ac-

curately computing the capacity factor. Installation of the additional meters would increase the cost of interconnection.

PG&E also disagrees with staff's alternative recommendation. PG&E agrees that no generation costs, except for spinning reserve, are incurred in providing standby service outside of peak hours. However, it contends that portions of the transmission and distribution system are dedicated to serve certain customers and that such costs are reasonably reflected in rates.

Edison objects to staff's proposed three-month ratchet provision. Edison claims that the 12-month ratchet is appropriate because the monthly standby charges are designed to recover 1/12th of the annual costs that Edison incurs in providing standby service. If the ratchet is reduced to three months, a higher charge would have to be imposed to recover the "full cost" of providing standby service.

Edison also opposes staff's proposed waiver of standby charges where the QF attains an 85% capacity factor in any particular month. Edison warns that such a provision would tend to eliminate standby charges altogether, since standby charges are already waived if the customer generation suffers an outage (and Edison supplies the demand) on-peak.

SDG&E agrees that existing ratchet provisions are reasonably modified to encourage reliable customer generation. It suggests that this might be done by extending the time effect of the ratchet and increasing the ratchet level for repeated outages.

SDG&E does have reservations about staff's proposed waiver of standby charges based upon performance. If staff's proposed waiver of demand charges during scheduled maintenance (discussed below) is also adopted, SDG&E contends that "the combination of the two waivers would mean that the QF pays neither a standby charge for demand nor a

demand charge when it actually imposes demand during scheduled maintenance." This is alleged to discriminate against retail customers who do pay for demand.

CMA states that demand ratchets and demand charges for generation, transmission, and distribution are not appropriate. Electricity used by the QF should be charged at the utility's marginal running cost. However, CMA agrees that standby schedules such as developed by Edison are an acceptable alternative for balancing FERC's intent with the purpose of standby schedules by reflecting significant differences in cost between periods.

The University of California (UC) prefers staff's alternative approach to standby rates. UC contends that, considering all QFs as a class and the diversification of probable QF outages, the inclusion of capacity or demand charges/payments in rates should operate to provide for any standby capacity requirements.

Solar Turbines International (Solar) supports the staff recommendation with regard to self-generators. Solar argues that SDG&E's existing ratchet-type standby charge operates inequitably in favor of generators who are generating a small percentage of their total requirements.

> "The cogenerators who are generating a large percentage of their capacity would opt for the flat charge rate, and the cogenerators and self-generators who are generating a small percentage of their power would opt for the ratchet clause, which means that the only generators which would be penalized by this ratchet clause would be the self-generators who are generating a large percentage of their power."

Solar recognizes that self-generators do not effectuate all of the objectives of PURPA. However, it contends that they do accomplish some of these as well as do cogenerators, and asks for appropriate treatment.

CEC recommends that rates be established without standby rates and that service be provided under conditions in tariff schedules. CEC states that under standby rates, the QF pays for its own reserve margin, but receives no benefit from its contribution to reduced reserve requirements. CEC suggests that certain distribution costs required to provide standby service can instead be recovered through facilities charges.

We find that the utility position is consistent with the increase in supply approach discussed in relation with capacity payments above. The CEC position is more consistent with the reduction in demand approach, as it recognizes the central proposition that the proliferation of cogeneration and small power production enhances reliability in the aggregate. However, we do not yet reach the conclusion drawn by CEC - that no standby rates should be charged.

Instead, we consider that standby rates are properly derived residually, based on the calculation of avoided costs and the determination of retail rates.

We earlier stated the proposition that standby rates do not apply when simultaneous purchase and sale is elected. In that case, the economics of the transaction are a function of two variables - the avoided costs and the retail rates. Simultaneous purchase and sale is a fiction - from the point of view of the utility, the operation of the system is exactly the same whether or not simultaneous purchase and sale is elected. We can think of no reason why the standby rate should be a major factor in a QF's decision whether to elect simultaneous purchase and sale. Therefore, the standby rate should be designed so that the total economic package is the same for a QF facing the election.

The present utility standby rates, which have been developed after much discussion and analysis, provide a good basis to achieve this balance. Standby rates apply to the QF that is serving its own load and requires backup power

for periods when its generation is down. If the QF is suffering an unscheduled outage, it pays the regular tariff rates for power purchased from the utility, which include a demand charge for that month. These rates when taken together provide for a reasonable recovery of backup utility generating costs when requisite consideration is taken of the noncoincidence of QF failure.

We will extend standby rates to all QFs, not just cogenerators, with demand schedules. We agree that these rates should be updated in general rate cases in proportion to increases in per kW capacity costs. We will also adopt the staff recommendations which provide for some options that should cover the diverse needs of different types of QFs. Currently, under certain utility price offers QFs must maintain 80% availability on-peak to receive firm capacity payments. The elimination of standby charges for QFs who attain an 85% on-peak capacity factor will provide a desirable incentive for reliable availability at the most critical times. Alternative standby rates should be promulgated for QFs on time-of-use rates to distinguish between the impact on the utility system of QF failure on-peak as opposed to off-peak. Failure on-peak imposes an incremental demand on the utility that is properly reflected in a demand payment, as in Edison's Schedule SCG-2. Failure off-peak imposes no such system demand problem. We adopt the staff's three-month ratchet proposal, as part of this rate scheme. This option should be appropriate for a QF with small generation output compared to its total demand. PG&E will be ordered to adopt a standby rate proposal consistent with these provisions.

D. Maintenance Power

Maintenance power is electric energy or capacity supplied during scheduled outages of the QF. By prearrangement, a utility can agree to provide such energy during periods when the utility's other load is low, thereby avoiding the imposition of large demands on the utility during

peak periods. Again, the concept does not apply when simultaneous purchase and sale is elected.

Staff states that PG&E now provides maintenance power to QFs under a special condition whereby customers are charged for energy furnished during scheduled maintenance under the regular rate schedule applicable to that customer. Added demand imposed on the utility by the scheduled outage is ignored for the purpose of computing demand charges under the regular rate schedule.

Staff recommends that QFs pay for energy delivered by the serving utility at regular rates during periods when their own generating unit is shut down. Staff proposes that PG&E's special condition (Special Condition 2 of Schedule S-1) be adopted by other utilities to provide for the waiver of added demand charges during scheduled maintenance periods. In adopting this provision, other utilities may take into consideration differences as to months that are appropriate to that utility for scheduling maintenance consistent with system peak loads. In establishing schedule maintenance periods, the utility will state that reasonable periods will be allowed and that deferrals of QF's requested schedule will be made on not less than 60 days' notice.

As an alternative, staff suggests that maintenance power rates be set at the utility's marginal cost:

> "The argument for charging the utility's marginal (avoided) cost is to keep the utility whole. Tariffs are now set considering, but not equal to, the marginal cost. When a QF uses maintenance power, the utility by definition suffers its marginal cost (change in total cost for a charge in output). The utility will lose money on maintenance power to the extent filed tariff rates are used and they are below the marginal (avoided) cost. Conversely, the utility will earn revenues above their expenses on maintenance power when

filed tariffs are used and they are above the marginal (avoided) cost."

In this case the rate charged is the same as the price the QF would otherwise receive as payment if it were delivering power (assuming it is paid based on current avoided costs).

Staff in its alternate further suggests that demand charge ratchets should not apply for maintenance power if the QF cannot schedule maintenance in the few months offered by the utility. Demand charges should apply for the month in which power is used, but should not be carried forward for the next 11 months.

SDG&E opposes the waiver of demand charges incurred for additional demand during scheduled maintenance periods. SDG&E states that while current schedules do waive any ratchet penalty for demands imposed during scheduled maintenance periods, all portions of retail rate schedules are appropriate to charge for power used. To eliminate any portion of the retail charge could be viewed as discriminating in favor of QFs.

SDG&E disagrees with the concept of dropping the ratchet penalty for unscheduled outages or outages scheduled without the concurrence of the utility. SDG&E views QFs as alternatives to utility generation and considers the ratchet provision a reasonable means of ensuring that the QF will build reliable units and schedule maintenance to avoid periods of high demand.

CMA states that if maintenance is performed during the scheduled period, no demand is imposed and demand charge is inappropriate. Limited (three months) ratchets may be appropriate for QF on-peak demand resulting from unscheduled breakdown. The shorter ratchet is proper recognition of the fact that requirements for maintenance power will not be simultaneous.

We find that this issue is properly addressed relative to the standard offer choices discussed above. The QF that chooses to provide as-available energy and associated capacity is under no obligation to schedule maintenance consistently with utility load requirements. Since payments to the QF are based on the utility's avoided costs, such a QF that is "out" during peak periods forgoes payments at the most lucrative time. As retail rates evolve toward marginal costs, such a QF also pays higher rates at such times by application of the retail rate schedule. We rely on such price signals to promote efficient operation of such facilities. We note that the higher the capacity payment at peak, the greater the incentive to schedule maintenance for off-peak periods. This relationship supports our conclusion that QFs providing as-available energy should be paid for capacity.

Those QFs that contract to provide firm energy are properly subject to the utility's scheduling requirements. We find the timing provisions set forth in PG&E's Special Condition 2 to Schedule S-1 to provide a reasonable standard for scheduling. The value of this commitment is correctly reflected in a higher capacity payment, as greater costs are avoided. Power during scheduled maintenance periods should be provided to the QF at the regular tariff rate. Added demand charges are appropriately waived for those QFs who are able to meet utility schedules. However, some QFs will have no opportunity to schedule maintenance to conform to utility peaks because of the seasonal nature of such QFs' operations. In such special cases, the demand ratchet triggered by this added demand should be limited to three months, with the exception that a three-month ratchet (three months including the month of occurrence) should apply for the first outage and three more months added for each additional outage (up to the present 12 months). PP&L, Sierra, and CPN shall be ordered to file rates consistent with this section.

E. Interruptible Power

Interruptible power is electric energy or capacity supplied to a QF subject to interruption by the electric utility under specified conditions. Many utilities have used interruptible service to avoid expensive investment in new capacity that would otherwise be necessary to assure adequate reserves at time of peak demand. Under this approach utilities assure the adequacy of reserves by arranging to reduce peak demand, rather than by adding capacity. Interruptible service is therefore normally provided at a lower rate than noninterruptible service.

Staff observes that Edison and SDG&E presently offer standby rates based on interruptible service. Such rates are available to large customers with loads greater than 1,000 kW who are on time-of-use rate schedules. Staff states that PG&E does not have an interruptible rate compatible with cogeneration by QFs. Staff suggests that PG&E be directed to file such rates.

Staff states that implementation of interruptible rates requires a phasing in, starting with large customers. Staff warns that interruptible service to smaller customers may cost more than the benefits are worth. Staff claims that more experience is needed with experimental offerings before such rates can be offered to smaller customers. However, utilities are required under PURPA to offer interruptible rates to all QFs unless a waiver is granted by this Commission.

PG&E agrees with staff. SDG&E states that:

> "The problem with expanding Interruptible Standby is the practical one of how does one interrupt the standby service without interrupting any remaining firm service. If the QF is willing to accept total service interruption or some positive measure can be taken to interrupt only the standby portion of the service, SDG&E has no objection to expanding Interruptible Standby."

SDG&E agrees with staff that interruptible rates may not be cost-effective for small customers.

The interruptible rate concept is applicable to QFs to the extent that QF's generation is used to serve its own load. We consider the FERC reference to "lower rate than noninterruptible service" as limited to customers of the same class, not that the interruptible rate must be lower than any noninterruptible rate. We recognize that interruption can provide both capacity and energy savings, and conclude that the actual rates should be based on the benefits that result from the avoided cost calculation and prevailing retail rates so that the appropriate price signal is available to the QFs.

As recommended by the staff, Edison and SDG&E should expand their current interruptible service offerings to cover all QFs above the current 500 kW minimum and PG&E should offer similar interruptible service to QFs to the extent that interruptible rates are filed for all large customers. PP&L, Sierra, and CP National should state their willingness to provide interruptible service to large QFs on a contractual basis. Interruptible rates for smaller QFs will be explored when more information is obtained on the costs and benefits of such offerings. Offerings to smaller QFs should occur at the same time that similar interruptible rate offerings are made to classes of customers below 500 kW.

VII. Standards for Safety

A. Introduction

FERC Regulation Section 292.308 provides that the appropriate state regulatory agency may establish reasonable standards to ensure system safety and reliability of interconnected operations. Standards may be recommended by any electric utility, QF, or other party. If standards are established, the state regulatory agency shall specify the need for such standards on the basis of system safety and reliability.

FERC's comments in regard to this section indicate that FERC:

> ". . .believes that the reliability of qualifying facilities can be accounted for through price: namely, the less reliable a qualifying facility might be, the less it should be entitled to receive for purchases from it by the utility.
>
> "As a result, the Commission has not included specific standards relating to the reliability in the sense of the ability of qualifying facilities to provide energy or capacity."

Instead, the focus is on safety equipment that can ensure that QFs do not energize utility lines during utility outages.

Our staff states as a basic objective that "reasonable uniform standards should be established and be part of each utility's new parallel generation tariffs." This matter is related to the problem of interconnection, discussed in the following section of this decision. The solution of these technical problems is crucial to the success of this entire program because the effectiveness of the standard offer will be defeated if protracted negotiations occur over conditions of actual delivery of the energy and capacity.

B. Staff Recommendation

Staff observes that various abnormal conditions can occur on a utility system. Some of these conditions will require detection devices and proper operation of protective equipment to prevent a hazard to the public or utility linesmen. For example, downed utility lines could pose a hazard to the public if a QF's generator continued to energize the line. Protective equipment must be provided to detect this condition and disconnect the QF's generator from the downed circuit.

Staff states that the QF should assist the utility in maintaining system integrity. For example, the QF's relays

should not frequently trip so that the QF cannot be relied upon to carry its share of the load. System disturbances also could result from inadvertent tripping of large QF generators. Staff proposes that utilities present adequate examples of how their guidelines deal with maintaining service standards and system integrity so that the QF is told clearly and simply not only what type of equipment is needed, but also the reasons the equipment is needed and what the equipment is expected to do.

Staff has identified three functional standards that it considers essential for safe and reliable operation, with a list of corollary conditions. The standards are as follows:

1. Sense and properly react to utility failures/ malfunctions;
2. Assist the utility in maintaining system integrity and reliability; and
3. Protect the safety of the public and utility personnel.

The corollary conditions are that the QF provide protection against the following adverse conditions, which can cause electric service degradation, equipment damage, and harm to others:

1. Prevention of inadvertent and unwanted re-energization of a utility dead line or bus;
2. Interconnection while out of synchronization;
3. Overcurrent;
4. Utility system load imbalance;
5. Ground faults;
6. Generated ac frequency outside permitted safe limits;
7. Voltage generated outside permitted limits; and

8. Poor power factor.

Staff suggests that QFs of 100 kW and larger may also be required to have overcurrent protection, utility system load imbalance protection, and a suitable power factor or power factor compensation up to nameplate generation capacity.

Regarding the respective responsibilities of QFs and serving utilities regarding design, installation, operation, and ownership of interconnection equipment, staff believes that the QF should be required to protect its own equipment in such a manner that faults or other disturbances on the utility system do not cause damage to the QF's equipment. Further, staff proposes that the QF take certain responsibility for protecting the public and utility operating personnel. Staff provides that the QF "may employ industrial quality interconnection equipment" for this purpose, with design review by the utility.

Except for the utility manual disconnect and feeder reclose blocking equipment, staff proposes that the QF have the option of owning, operating, and maintaining the interconnection protective equipment, or paying the utility. The utility must complete design review within a specified period and respond in writing, either accepting the QF's plans or providing detailed information regarding deficiencies.

Staff states that progress is being made in arriving at fairly uniform interconnection requirements. It asks that each of the utilities provide illustrations of how its requirements would apply to certain specified situations. Staff proposes that each utility complete its guidelines based on staff's recommendations in this matter.

Staff classifies three sizes of generating facilities: small - below 100 kW; medium - 100 kW to 1 MW; and large. Staff recommends that utilities review their requirements for small size facilities with the objective of simpler re-

quirements and standardization. Dedicated transformer requirements should be limited to not greater than 1.15 times the QF's generator nameplate capacity. Daily logs of generator trips and separations for small QFs shall not be required. Staff suggests that utilities establish requirements for the medium-sized facilities that are simpler than for the larger size. For all sizes staff suggests that utilities include diagrammatic examples of interconnection arrangements in their guidelines.

Staff state that utilities now require a voltage and frequency window-type of control for induction generators and other utility line-commutated generating devices, to assure such devices will trip off the line and stay off in an emergency. Staff contends that this practice is the lowest cost control method capable of performing well, and staff recommends its continued use. However, staff suggests that utilities examine other means of safeguarding the public and operating personnel, while assuring system reliability.

Staff proposes that these principles be incorporated in parallel generation tariffs to be filed by each utility under General Order 96-A, with modifications to be reviewed before becoming effective to protect QFs from arbitrary changes.

Staff states that an alternative and more time-consuming procedure would be for this Commission to issue detailed interconnection regulations in the form of a general order. Staff recommends that such action not be taken at this time, as it considers its listed functional requirements and conditions as an adequate basis for the utility tariffs. Staff warns that protection equipment is still evolving and detailed regulations might impede such evolution. Staff states that it would be under a considerable burden if it has to develop such standards. Staff describes the tariff approach as less cumbersome and possibly leading to more rapid adoption of equitable and standardized rules. Staff

suggests that the utilities should be given the opportunity to work cooperatively with QFs in developing such rules and that we consider a general order only if this approach fails.

As the final point in this regard, staff addresses the question of what requirements should be imposed on QFs regarding liability and indemnification. Staff recommends that utilities be permitted to include provisions that restate common law principles of liability and indemnity in QF contracts. Under staff's approach, utilities may require a QF to provide proof of liability insurance coverage in a commercially reasonable amount not to exceed a reasonable estimate of the utility's relevant actual risk of loss. This requirement would be waived where the QF is 20 kW or less, providing its generator delivers power to the utility grid through a dedicated transformer. Staff proposes that utilities may require a QF to name the utility as an additional insured under the QF's liability insurance, except when such naming makes it impossible for the QF to obtain liability insurance or in cases where the QF is 100 kW or less in size.

C. Utility Responses

PG&E agrees generally with staff's identified functions of protective equipment. PG&E suggests that "harmful wave forms" be added as an additional adverse condition that the QF is required to provide protection against.

PG&E agrees generally with staff's discussion of QF and utility responsibilities. However, PG&E does propose to allow utilities to require QFs of 1 MW or larger to use utility grade interconnection equipment, while QFs of less than 1 MW may employ industrial quality interconnection equipment that meets state and local codes.

PG&E proposes to expand the scope of staff's treatment of small QFs to allow utilities to require QFs to maintain records of when the unit was not available for operating

maintenance outages, trip operations due to faults, and other unusual events, and to allow the utilities to reserve the right to review such records.

Edison objects to staff's suggestion that "industrial quality relays" are adequate for all interconnection protection, regardless of size. Edison states that there are good reasons to employ utility quality devices in specific instances where close coordination of the utility and QF protective devices is required to maintain reliable service from the QF and the utility. Edison claims that large QF generators are significant sources of short circuit current when connected to a distribution system and must be closely coordinated with existing utility relays to ensure reliable operation and avoid false operations. In many cases industrial grade relays do not have the necessary flexibility, stability, or calibration accuracy to allow coordination with utility system relays.

Regarding the respective responsibilities of the QF and utility with respect to equipment design, installation, operation, and ownership, Edison recommends that operators who elect to provide the interconnection protective equipment themselves shall be responsible for any damage or injury to the public, utility personnel or equipment, or to other utility customers and their equipment, caused by the generating facility. If the operator elects to have the utility provide the equipment, the utility shall be responsible for such damage or injury.

Edison characterizes staff's recommendation regarding liability and indemnity provisions as "acceptable as far as it goes." However, Edison claims that the common law has been supplemented to some extent by statutory law and suggests that a restatement of that statutory law appear in contracts. In particular, Edison refers to an alleged obligation to reimburse the indemnitee for all costs incurred or all out-of-pocket costs or all judgments paid or

all demands suffered, including appropriate attorney's fees and other costs of litigation.

SDG&E agrees with staff's recommended functional standards. However, it does not agree that staff's proposed condition (e) is required for QFs under 200 kW, because most customers at that level are expected to connect to its system with a delta wye transformer.

SDG&E agrees that the QF has responsibility for protecting its own system, equipment, the public, and utility operating personnel. It further agrees that QF designs for interconnection should be subject to utility review for functional adequacy. SDG&E offers its own schedule for review, suggesting a minimum of six and a maximum of eight weeks. SDG&E does not agree that the QF should have the option of paying the utility to install interconnection protection equipment. SDG&E objects that the QF should not be allowed "to transfer the funding of this responsibility to the utility."

With regard to liability and indemnification issues, SDG&E states that staff's reference to common law is neither helpful nor appropriate. SDG&E suggests that utilities and cogenerators should be permitted to continue as they have in the past to write indemnification provisions as they feel necessary.

SDG&E objects to staff's treatment of QFs of very small QFs that provide power to the grid through a dedicated transformer. SDG&E states that size has little to do with the extent of liability which may be incurred by a QF due to an accident. SDG&E asserts that, as the size the the QF diminishes, the need for insurance increases because the QF's own resources tend to be smaller. Based on the same reasoning, SDG&E opposes staff's recommendation that small QFs be excused from naming the utility as an insured under specified circumstances.

D. Third Party Comments

CEC agrees that this Commission should take definitive action regarding interconnection and parallel operation to establish as much standardization as feasible. CEC states that staff did properly require the QF to protect against electric service degradation, equipment damage, and harm to others by providing a series of events for which protection must be provided. However, CEC complains that staff left the establishment of the actual criteria to the utilities. CEC suggests that interconnection requirements may be appropriately considered in a separate proceeding because of the complexity of the issue, but should not be left unresolved.

Union is concerned that utilities may impose costly and unnecessary burdens on QFs in the absence of clear interconnection guidelines. Union states that interconnection costs should be net costs and the Commission should incorporate an appropriate discount factor in order to recognize that some interconnect costs would have been incurred if the utility had constructed its own facility. Further, Union proposes that the utility's ability to oversee and approve the technology and equipment selection of a QF should be narrowly confined.

As stated above, MPS requests that we provide for evidentiary proceedings to investigate and adopt standards to ensure system safety and reliability of interconnected operations. MPS states:

> "This Commission should recognize that the control methods available to QFs inherently limit the technological opportunities which can be safely and economically developed and offered in the marketplace."

MPS objects to the unilateral imposition of burdensome or incompatible control methods by utility personnel who are neither qualified nor familiar with the technologies to which these methods will be applied.

Mr. Holbrook of Power Towers, Incorporated (Holbrook), observes that, of the several utility intertie proposals, staff seems to endorse the most stringent. In particular Holbrook objects to the isolated transformer requirement as technically unnecessarily and economically devastating to many potential applications for wind power. Holbrook also describes the difficulties of a wind generator vendor and buyer where a third party (the utility) is in a position to subsequently determine the feasibility of a facility.

Henwood states that there will be honest differences of opinion between QFs and utilities regarding appropriate types and quality of interconnection facilities. Since these differences can have rather significant cost impacts, Henwood states that Commission review of utility interconnection requirements is necessary to reach an equitable solution.

Henwood argues that the only way the QF can maintain control over interconnection costs is to have the option to design, construct, and maintain is own interconnection facilities.

Henwood objects to the utilities being named as insured, as suggested by staff, because of the cost to the QF.

Pan Aero states that the QF should have several options regarding interconnection costs, including: (1) to pay for its interconnection equipment and to own and maintain such equipment; (2) to pay the utility monthly charges for utility ownership and maintenance of interconnection equipment; and (3) to own the interconnection equipment and pay the utility only for maintenance of such equipment.

Pan Aero points out that under the staff recommendation, the QF must protect its own equipment from faults on the utility system, as well as protect the utility and its ratepayers from faults in the QF's system. Pan Aero contends that the QF should have no greater burden than the utility, and asks: "If the QF must protect the utility, why

shouldn't the utility also protect the QF from faults in the utility system?"

Great Western suggests that the Commission should keep in mind the cost of interconnection equipment and the burden such costs can impose on QFs. Great Western agrees that the QF should have the option of owning and installing the interconnection equipment and that the utility should pay for any equipment the utility installs above the standard. Great Western asks that the Commission be prepared to resolve any disputes between QFs and utilities concerning the adequacy of proposed interconnection plans.

Great Western argues that there is no need for indemnity provisions. It claims that so long as each party acts with due diligence and in accordance with good engineering practice, each should have no liability to the other. Neither the utility nor the QF should be required to assume greater responsibility for losses resulting from its acts or the failure of its equipment. With respect to liability insurance, Great Western asks that such requirements be limited to preclude utilities from imposing onerous requirements on QFs.

E. Discussion

As stated above, the effectiveness of the standard offer will be substantially impaired if the parties nevertheless must negotiate terms and conditions of the physical connection to the utility network. We therefore believe that general uniform interconnection safety standards should be specified. A rulemaking proceeding such as this is a proper vehicle for adoption of policy guidelines for interconnection which assure integrity of both the utility and QF systems consistent with public safety.

As indicated above, staff has identified several standards which are essential for maintaining safety and reliability. No party has effectively disputed these standards, and we shall adopt them. Each utility should file parallel gener-

ation tariffs which incorporate the staff-recommended reliability standards plus a prohibition on harmful wave forms. The tariffs should incorporate compatible interconnection guidelines currently in effect, and should specify separate guidelines for QFs below 100 kW, between 100 kW and 1 MW, and above 1 MW. We agree with staff that for small QFs under 100 Kw, simpler requirements should apply. We therefore find reasonable the dedicated transformer requirements and reporting standards recommended by staff for QFs under 100 kW. Similarly, we expect simplified interconnection requirements for QFs between 100 kw and 1 MW. For all QFs, diagrams of illustrative interconnection configurations should be included.

We expect that the QF will attach interconnection equipment which is compatible with the protective standards incorporated within the utility's parallel generation tariffs. We agree with staff that the QF has responsibility for conforming to these standards to assure system integrity and safety. By placing this responsibility upon the QF we do not believe it necessary to endorse any specific type of interconnection equipment so long as the QF's equipment meets the protective standards outlined. We expect, however, that QF equipment will meet applicable and local safety codes. Except for the utility manual disconnect and feeder reclose blocking equipment, the QF shall have the options of owning, operating, and maintaining the interconnection equipment, or paying the utility to do so. With this option the QF can maintain a degree of control over interconnection costs. Costs of equipment in excess of the minimum standards we have prescribed should be borne by the party requesting the equipment.

Liability and indemnification provisions contained in the standard offer should restate principles of common law and current statutes. We believe it appropriate for a QF to provide coverage at a commercially reasonable amount, consistent with the utility's actual risk of loss. In addition it is reasonable to require QFs over 100 kW in size to

name the utility as an additional insured under the QF's policy, except when such naming precludes the QF from obtaining liability insurance. This requirement is consistent with generally recognized practices in commercial contracts.

The tariffs which the utilities shall file will be subject to preliminary review by our staff, and accepted for filing on an interim basis. Unique situations should be handled by a deviation procedure under General Order 96-A. We make these tariffs interim in recognition that interconnection requirements are still evolving. We make no final judgment at this time regarding specific technical requirements necessary to assure operating reliability. We recognize that wide differences of opinion exist as to particular requirements which may need to be the subject of a general order. Accordingly, after six months we shall review these tariffs to assess their effectiveness, and, at that time, shall determine whether more detailed requirements are appropriate.

VIII. Interconnection Costs

A. Introduction

FERC Regulation Section 292.306 provides that each QF shall be obligated to pay any interconnection costs which the State regulatory agency may assess against the QF on a nondiscriminatory basis with respect to other customers with similar load characteristics. The State regulatory agency shall determine the manner for payment of interconnection costs, which may include reimbursement over a reasonable period of time.

FERC Regulation Section 292.101(b)(7) defines "interconnection costs":

> " 'Interconnection costs' means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility

> directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs."

There is an obvious relationship between certain of these costs and the standards of operating reliability discussed above.

B. Positions of the Parties

Staff states that in order to determine what are reasonable interconnection costs it is first necessary to determine what are the minimum acceptable interconnection standards.

Staff recommends that a procedure similar to the special facilities provisions of existing tariff schedules should be established for interconnection costs. Staff proposes that the QF have the option to either: (1) advance to the utility the estimated net installed cost of the interconnection facilities and also pay the monthly cost of interconnection ownership charges as authorized in the utility's interconnection tariff, or (2) not elect to advance the estimated installed cost of the interconnection facilities and instead pay a monthly combined charge for added facilities as authorized in the interconnection tariff. Such a charge would cover both facilities and ownership costs. With the second option, the customer agrees to pay the net unpaid balance, including interest, of the installed cost of the interconnection facilities, plus removal charges, less estimated salvage value. Staff proposes that CP National Corporation

be excused from this approach on account of its status as a buyer of its entire requirements in California. Instead, CP National Corporation could include the method of payment either in its contracts with individual QFs or in separate facilities contracts.

PG&E agrees with staff's recommendation, with certain modifications. PG&E suggests that when an agreement is terminated, the QF may be entitled to a refund of part of its advance payment to the utility. PG&E proposes that the QF may be required to make an additional payment to cover the cost of the equipment removal and outstanding installation expenses.

Edison states that although staff's list of protective functions is relatively complete, specific instances will require additional equipment, most likely in the cases of large generators. In such cases Edison contends that the need for the equipment will be apparent and the utility and QF will mutually agree that it is necessary. Edison suggests that the QF should pay for the equipment in such cases.

SDG&E states that the costs of interconnection as specified by the utility should be borne by the QF. If the Commission finds that SDG&E's interconnection guidelines are not reasonable, SDG&E is "willing to discuss revisions" to its interconnection guidelines.

SDG&E objects to staff's proposal that the QF have the option to obligate the utility to make a capital investment for interconnection costs. SDG&E states that to require the utility to add this funding burden to its other capital requirements negates one of the largest benefits of cogeneration. SDG&E suggests that utility funding be at the option of the utility.

C. Discussion

The basic proposition is straightforward. Each QF is responsible for the cost of interconnection which exceeds

the cost the utility otherwise would incur to connect the QF as a customer. The costs of interconnection borne by the QF shall be only those costs necessary to meet the minimum reliability standards discussed above. The cost of additional requirements imposed by the utility shall be borne by the utility.

We are satisfied that staff has provided a sound payment basis, as modified by PG&E. SDG&E's concern regarding the possible financial burden of utility financing can be taken into account in calculating avoided costs, if an evidentiary basis can be shown.

Some QFs, particularly smaller ones, may require distribution-type line extensions. Wherever such line extensions are comparable to those serving residential or commercial customers, the charges to the QF should also be comparable to those charged other utility customers, including refunds to customers. Distribution-type line extensions costs presently are covered in utility Tariff Rules Nos. 15, 15.1, and 15.2. Unless the QF's load characteristics on any line extensions required for the QF are different than for regular utility customers, the line extension costs should be the same for each to avoid discriminatory pricing practices.

IX. System Emergencies

FERC Regulation Section 292.307 provides that a QF shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent: (1) provided by agreement between such QF and electric utility; or (2) ordered under Section 202(c) of the Federal Power Act. During any system emergency an electric utility may discontinue (1) purchases from a QF if such purchases would contribute to such emergency; and (2) sales to a QF provided that such discontinuance is on a nondiscriminatory basis. A "system emergency" is a condition on a utility's system which is likely to result in imminent

significant disruption of service to customers or is imminently likely to endanger life or property.

There is little discussion of this point among the parties. The standard offer adopted by this decision for as-available electricity does not obligate the QF to be available during an emergency. Staff states that there are adequate incentives built into pricing offers to encourage QFs to be online when system emergencies are likely to occur.

Capacity payments for firm capacity under standard of

fers neither obligate the QF to separate its load and resources nor obligate QFs to curtail their own load during emergencies. The added costs of such separation of the load and resource would be excessive and of questionable value. QFs that continue to buy power from the utility in excess of their generation, through standby rates or under a simultaneous purchase and sale arrangement will, of course, be subject to curtailment in accordance with systemwide curtailment policies as established by the Commission. To qualify for a firm capacity payment, however, the QF will be expected to operate at maximum capacity on notice to meet utility needs for capacity during peakload periods and emergencies, consistent with limitations which may exist at the time in the QF's equipment, fuel, or other source of energy. Capacity, in excess of the QF load, should be available to the utility during emergencies to the extent the utility can use the electricity and it is practical for the QF to make delivery.

Utility Incentives

We believe that one idea not addressed in this proceeding deserves consideration. In most markets, brokers receive a fee for their role as intermediaries between buyers and sellers. Similarly, it could be argued that utilities in their roles as intermediaries between QFs and ratepayers should receive a small fraction of the avoided cost payment as a brokerage fee. For example, utilities might

receive one-half of one percent of the avoided cost payment, leaving QFs with the remaining 99.5 percent. We specifically are not suggesting here that consumers pay an additional payment to utilities beyond the avoided cost. We invite interested parties to comment within 45 days on whether utilities should receive such a fee as an incentive for good performance in their role as a broker. We would also be interested in any specific proposals for establishing such fees.

X. Implementation

In this decision, we have decided that a qualifying facility should be presented with options in the standard offer, each of which is consistent with avoided cost principles but which also has different terms and conditions to meet different needs of the qualifying facilities. The options we order in this decision today do not exhaust the different arrangements that we can envision that are consistent with avoided cost pricing. We may conceivably order others in the future, or refine those adopted prospectively as appropriate.

As we stated earlier, additional hearings are required to complete this process. However, some offers are similar to those that have been filed already by the utilities in response to Resolution E-1872 (March 4, 1980), and we expect that these offers can become available without prolonged review. Others will require further hearings. Specifically, the "as-available" offer and the offer for firm capacity (based on the short-run marginal cost methodology) should be implemented quickly, while the levelized, escalating, and resource plan-based offers will require more extensive hearings.

Accordingly, we adopt the following schedule for submission.

Each respondent shall file the offers for (1) as-available energy and capacity and (2) firm capacity (based on the

short-run marginal cost methodology) with this Commission as an application within 45 calendar days from the date of this order. The offers should include contract terms and conditions complying with the guidelines developed in this decision. Utilities filing these applications shall serve them on all parties to this proceeding.

Because the forms of the as-available and firm capacity offers are similar to the interim price schedules currently being offered by the respondents under Resolution E-1872, and because the information to support the prices contained in these offers is developed in general rate cases, these offers may take effect expeditiously. The staff will review these offers upon filing, and the offers will take effect two weeks after the date of filing unless the Commission acts to suspend any of the offers, pending review at hearing. QFs may accept these offers as soon as they become effective, and costs incurred by utilities pursuant to the resulting contracts are reasonable and may be recovered in the same fashion as other purchased power costs.

Each of these offers will be reviewed in subsequent evidentiary hearings which may result in prospective modifications to the offers but which in no way will affect either the validity of contracts resulting from the initial standard offers or the utilities' recovery of their costs under such contracts. These evidentiary hearings, furthermore, will be narrowly restricted to the issues of each utility's compliance with the requirements of this decision and of the factual basis for the prices contained in each standard offer. The evidentiary proceeding will *not* be a forum for reexamining the issues resolved in this decision. QFs who believe that beneficial modifications to the standard offers may result from the evidentiary hearings may accept the utilities' initial standard offer for a short term and later accept any modified offer upon the expiration of the initial contract. A QF who is satisfied with a utility's initial standard offer may contract for a longer term with

the assurance that any later modifications will be prospective only and will not alter its agreement with the utility.

In D.93054 dated May 19, 1981 (as modified in D.93393 dated August 4, 1981), we required a provision in respondents' interim price schedules which gave QFs who entered into contracts with utilities after May 19, 1981 and before the conclusion of this proceeding the option of amending their agreements to conform with "the final decision and order" in OIR 2. Because such QFs were apparently somewhat satisfied with their agreements with the utilities, and to avoid excessive amending of these agreements, we determine that the proper time for consideration of conforming amendments is the completion of our evidentiary review of the appropriate standard offer. Thus, after we have reviewed, for example, a utility's standard offer for as-available energy and capacity and have ordered any necessary modifications, a QF who had earlier contracted on an as-available basis with that utility may convert its contract to the new standard contract. Such a QF need not, of course, wait until the completion of our review of all forms of the standard offer before exercising its option.

The other standard offer contracts (e.g. levelized, escalating, and resource plan-based contracts) adopted in this decision will require more extensive hearings. These offers shall be submitted as applications to the Commission under the guidelines set out above within 90 calendar days from the date of this order and shall be served on all parties to this proceeding. We will hold prehearing conferences in those proceedings after they are filed, and determine the scope of the subsequent hearings.

Findings of Fact

1. The California Legislature and the Public Utilities Commission have a longstanding demonstrated interest in promoting cogeneration and small power production.

2. Cogeneration and small power production have also been the subject of federal actions intended to promote their development, particularly Sections 201 and 210 of PURPA.

3. Each electric utility is required under Section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under Section 201. PU Code Section 2821 enables the CPUC to establish equitable charges for purchases of power from private energy producers.

4. For such purposes electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers.

5. Section 210 also requires electric utilities to provide electric service to QFs at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers.

6. Section 210 further requires the FERC to prescribe rules as FERC determines necessary to encourage cogeneration and small power production.

7. On February 19, 1980, FERC issued its final rules implementing Section 210. These regulations require that electric utilities purchase electric energy and capacity from qualifying cogenerators and small power producers at a rate equal to the utility's avoided cost of generating the power itself or purchasing it elsewhere.

8. The implementation of the Section 210 rules is reserved to the appropriate state regulatory authorities.

9. By OIR 2 dated September 3, 1980, this Commission initiated this proceeding for the purpose of establishing standards under the FERC rules, to further implement our decision in D.91109, and to discharge our responsibilities under PU Code Section 2821.

10. Among the criteria describing a QF under Section 201 is a limit of 50% utility equity ownership interest.

11. Utility ownership of a QF will require scrutiny of the relationship between the utility and its affiliate.

12. Utility ownership of an energy resource developed by a nonutility QF does not defeat the application of avoided cost principles.

13. The profitability of sales of a utility-owned resource to a QF should be considered in a general rate case.

14. Sierra and PP&L are unique, in view of their relative size, location, and system configuration.

15. A water diversion does not involve the direct sale of electricity by a QF and therefore is beyond the scope of this proceeding.

16. Under the FERC rules, each regulated utility is required to file projections of its incremental energy and capacity costs and its construction schedules with its state regulatory authority for review and use in setting appropriate rates for purchase and sale of electricity between electric utilities and QFs.

17. FERC rules require certain specified factors to be taken into account to the extent practicable in determining avoided costs.

18. FERC rules require certain specified data to be filed by electric utilities for the purpose of avoided cost calculations.

19. Additional data, as proposed by staff, would be valuable in developing standard offers and in aiding QFs in forecasting the direction of avoided costs over time.

20. CP National buys its electrical requirements from PG&E and Nevada Power Company.

21. Social costs are tangible but hard to quantify factors that are difficult to include in avoided cost calculations.

22. FERC rules provide for a standard offer for purchases by a utility from a QF.

23. FERC rules provide that utility purchases from a QF shall be at the utility's avoided cost.

24. Avoided costs reflect the added costs to a utility of producing an additional unit of electricity.

25. Purchases by an electric utility from a QF under a standard offer are recoverable through ECAC or other appropriate procedures without further review.

26. The standard offer is a choice of contract terms at the QF's sole option.

27. The QF may choose to provide firm energy or capacity, based on either the utility's avoided costs at the time of delivery or the time the obligation is incurred.

28. The QF may choose to provide energy as-available, based on the utility's avoided cost at the time of delivery.

29. Calculation of the utility's avoided energy cost at the time of delivery is based on the variable cost of providing an additional unit of electricity.

30. As-available energy payments are properly differentiated by time-of-use.

31. Transmission and distribution costs are not practically treated on an individual basis and should be treated in the aggregate.

32. Costs or savings resulting from variations in line losses should be aggregated for standard offer purposes.

33. The "reduction in demand" model is a useful tool for analyzing whether QFs should receive a capacity payment for the delivery of as-available energy.

34. Aggregate capacity value is recognized by the "reduction in demand" approach consistent with FERC regulations.

35. The higher the payment for capacity associated with as-available energy, the more likely such capacity will be provided during system peaks.

36. QF production will grow in increments that will provide an opportunity to prove reliability through experience.

37. The impact on the system of the failure of individual QFs is not comparable to the impact of the failure of a large central station facility.

38. Calculation of the utility's avoided capacity cost at the time of delivery is based on the utility's estimate of current shortage costs.

39. As-available capacity payments should be based on performance, adjusted by time period, and paid in cents per kWh.

40. The as-available capacity payment is based on 100% of the annual capacity value of the utility's current shortage costs.

41. As-available capacity costs include generation and generation-related transmission costs.

42. Contract length, notice, termination, and sanction provisions are not related to as-available capacity value.

43. Capacity payments for as-available hydro should not differ from other technologies.

44. The option for the QF to be paid based on costs calculated at the time the obligation is incurred allows a QF the certainty of a known price.

45. The energy component in a long-term contract is based on forecasted short-run marginal operating costs.

46. FERC rules allow for levelized energy payments.

47. Estimates of future fuel costs are an integral part of utility resource planning.

48. Forecasted energy payments for up to five years are reasonable.

49. Levelized energy payments are not an appropriate payment option under the standard offer.

50. To the extent that an individual QF provides firm capacity that allows additional costs to be avoided, these additional costs should be reflected in a higher payment to the QF.

51. The firm capacity payment associated with a short-run energy cost is based on a short-run marginal cost methodology in which the capacity payment reflects the costs of a shortage to the utility.

52. Firm capacity payments properly reflect the QF's availability during peak periods, including: dispatchability; reliability; contract duration, termination, and sanctions; scheduling of outages; and availability during emergencies. The value of these factors should be computed on a cents per kWh basis as well as a dollars per kW per year basis, so that a QF that exceeds reliability standards will be paid accordingly.

53. The payment for firm capacity should be uniform to all QFs, except hydro.

54. Special provisions are necessary for small hydro QFs offering firm capacity to reflect adjustments for dry year unavailability.

55. The firm capacity value of a hydro QF is reasonably based on an average of the five lowest flow years.

56. Payment for firm capacity should differentiate between small hydro producers based on actual stream flows.

57. A levelized firm capacity payment for up to thirty years is reasonable.

58. Up-front capacity payments would introduce an element of substantial risk into the standard offer.

59. Loans and guarantees greatly increase the expense to the ratepayer and should be provided only after a thorough evaluation of the proposed project.

60. Insofar as an improved reserve margin always improves reliability at least to some degree, the capacity payment always has some positive value.

61. FERC rules provide that utility purchases are not required during any period during which, due to operational circumstances, purchases from QFs will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

62. Economy energy purchases are not a condition that permits a utility to refuse to purchase from a QF.

63. The right to refuse purchases from QFs arises only when the avoided cost at the time of delivery would be less than zero.

64. The QF is entitled to reasonable notice prior to a utility's refusal to purchase.

65. Notice to baseload or intermediate QFs of a utility's refusal to purchase at least 48 hours is a reasonable minimum. Two hours notice is reasonable for QFs with peaking-type plants.

66. Utilities should set priorities, as proposed by staff, for refusals to purchase from QFs.

67. Before refusing to purchase the utility should undertake to make economy sales on behalf of the QF. In such cases the QF is paid based on the economy energy price and no wheeling charge may be imposed by the utility.

68. A report should be filed annually by each utility regarding refusals to purchase from QFs.

69. Simultaneous purchase and sale is a regulatory convention that allows a QF simultaneously to sell its own

generation to the utility while purchasing its requirements from the utility.

70. Generally, the QF should be able to convert to and from simultaneous purchase and sale subject to reasonable notice and compensation provisions. QFs which select the option of forecasted or levelized energy payments under a long-term capacity contract must commit their entire output to the utility.

71. FERC rules require standard rates for purchases from QFs with a design capacity of 100 kW or less.

72. The standard offer for small QFs should be expressed in terms of cents-per-kWh and be offered on either a time or nontime differentiated basis.

73. The small QF should have the choice whether to have time differentiated payments, subject to paying for the necessary meter.

74. Time differentiated metering will be required for small QFs electing the simultaneous purchase and sale option and QFs selling a majority of their power to the utility under the sale of surplus power option.

75. Advance review will reduce the utility's risk in signing nonstandard contracts.

76. Payments under nonstandard contracts are recoverable through ECAC or other appropriate proceedings upon a showing of reasonableness.

77. A contract negotiation schedule would be difficult to enforce.

78. Wheeling can make a material contribution to cogeneration and small power production.

79. FERC rules require that each utility provide: (1) supplementary power; (2) backup power; (3) maintenance power; and (4) interruptible power.

80. FERC regulations provide that the rate for sales of backup or maintenance power should not be based on an assumption that QFs will fail to provide power simultaneously or during system peaks, or both.

81. QFs are now furnished supplementary power under regularly filed tariffs applicable to all customers of the same class as the particular QF.

82. Standby rates should not be a major factor in a QF's decision whether to elect simultaneous purchase and sale.

83. Current basic standby rate levels in dollars per kW per month are reasonable as modified in this decision and may reasonably be increased in general rate cases in proportion to increases in per kW capacity costs.

84. The elimination of standby charges for months in which a QF attains an 85% on-peak capacity factor will provide a desirable incentive for reliable availability at the most critical times.

85. Standby rates should be derived residually, based on the calculation of avoided costs and the determination of retail rates.

86. Since payments to QFs are based on the utility's avoided costs, a QF that is undergoing maintenance during peak periods foregoes payments at the most lucrative time.

87. It is premature to develop standby rates for QFs not currently served by rate schedules with demand schedules.

88. Standby rates should generally be extended to all QFs with demand schedules. They should not be finalized for new technologies like photovoltaics until more analysis is possible.

89. It is reasonable to establish time-of-use-based standby rates to distinguish the impact of QF failure upon

a utility. On-peak failure is appropriately accounted for with a demand payment with a three-month ratchet.

90. QFs that contract to provide firm capacity are properly subject to the utility's scheduling requirements.

91. The provisions set forth in PG&E's Special Condition 2 to Schedule S-1 provide a reasonable standard for scheduling maintenance and exemptions from added demand changes.

92. Some QFs will have no opportunity to schedule maintenance to conform to utility peaks because of the nature of the QF's operations.

93. It is reasonable that QFs with seasonal operations shall pay added demand charges with a three-month ratchet if they cannot coordinate maintenance with a utility's schedule.

94. Interruptible rates should be available to larger QFs on time-of-use rates.

95. Interruptible service can provide both capacity and energy savings.

96. FERC rules provide for reasonable standards to ensure system safety and reliability of interconnected operations.

97. Such standards are crucial to the success of this entire program because the effectiveness of the standard offer will be defeated if protracted negotiations occur over conditions of actual delivery of energy and capacity.

98. Staff has identified various functional standards which are essential for safe and reliable operations.

99. FERC rules require that each QF shall be obligated to pay any interconnection costs which the state regulatory agency may assess against the QF on a nondiscriminatory basis.

100. Interconnection costs are related to reliability standards.

101. Interconnection facilities are analogous to special facilities provisions of existing tariffs.

102. FERC rules require a QF to provide energy or capacity to an electric utility during a system emergency only to the extent: (1) provided by agreement between such QF and electric utility; or (2) ordered under Section 202(c) of the Federal Power Act.

103. Adequate incentives are built into standard offers to encourage QFs to be on-line when system emergencies are likely to occur.

Conclusions of Law

1. The rulemaking procedure is an appropriate vehicle for establishing standards governing prices, terms, and conditions of electric utility purchases of electric power from qualifying cogeneration and small power production facilities under FERC rules.

2. Motions by Edison, SDG&E, and MPS are denied.

3. A QF owned in part by an electric utility is eligible for full avoided costs under the conditions adopted in this proceeding.

4. Utilities and QFs remain free to negotiate contracts containing terms which differ from those of the standard offer.

5. Additional data as proposed by staff is useful in validating the avoid cost methodology.

6. The standard offer should provide for a capacity payment for as-available energy.

7. The standard offer should provide for a forecasted energy payment.

8. A QF willing to commit to provide firm capacity should receive a higher capacity payment than a QF on an as-available basis.

9. The standard offer should provide for a levelized firm capacity payment for up to thirty years.

10. The standard offer should provide for prices based on long-run marginal cost.

11. Loans and guarantees should not be included in the standard offer.

12. Refusals to purchase should be arranged by technology and reasonable notice should be provided.

13. Simultaneous purchase and sale should be at the QF's option, subject to reasonable conditions.

14. The standard offer should provide for simplified rates for QFs of 100 kW or less.

15. Section 2821 of the Public Utilities Code does not require advance review of nonstandard contracts.

16. A utility's willingness to wheel should be considered as part of its overall conservation activities.

17. Utilities should offer supplementary power, standby power, maintenance power and interruptible power consistent with this decision.

18. The Commission should entertain formal complaints raised by QFs who can demonstrate that the utility has failed to bargain in good faith. A utility found not to have bargained in good faith would stand in violation of this order and will be open to potential punitive action by this Commission.

ORDER

IT IS ORDERED that:

1. Within 45 days of the effective date of this order, each utility shall file the following data:

a. System avoided operating (running) cost in cents per kWh annually and by costing period in nominal and real cents per kWh by voltage level for 10 years. The marginal fuel (s) by each costing period and the nominal and real escalation rates used to estimate their cost will be reported. System incremental heat rates by time of use for 10 years (correlated with incremental fuel costs) will also be provided.

b. The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, for capacity retirements and for terminations of contracts for purchased capacity for each year during the planning horizon, for a minimum of 10 years.

c. The estimated capacity costs at completion of the planned capacity additions and planned firm purchases, on the basis of dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh (using the projected capacity factor) and the associated energy costs of each unit in cents per kWh. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

d. The estimated capacity costs of transmission and distribution plant in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

e. The estimated operation and maintenance, administrative and general, and all other fixed

and variable operating expenses for avoided capacity and energy used in avoided cost calculations, expressed in dollars per kW, dollars per kW per year, dollars per kW per month, and cents per kWh.

f. The system marginal cost loss factors by time of delivery and voltage for energy and capacity from generation to each voltage level. Also, the net system aggregate loss factors by time of delivery and voltage for energy and capacity, to reflect avoided losses resulting from a reasonable mix of QFs.

g. The levelized annual cost rates for translating investment costs into annual charges, and present value rates used in any present value calculations.

h. The costs expressed in paragraphs a-e above will be on a test year (real) dollar basis or on an escalated basis, with the forecast escalation rates reported in either case. All assumptions of escalation rates, discount rates, incremental fuel increases, incremental heat rates and such, will be stated.

2. Within 45 days of the effective date of this order, each utility shall file by application and serve upon all parties to this proceeding, a standard offer for as-available energy and capacity, and for firm capacity based on short run marginal cost methodology.

3. The above offers shall become effective two weeks after the date of filing, unless otherwise suspended by the Commission. Prior to compliance hearings, these offers shall be considered initial offers. Upon becoming effective, utilities shall send copies to all QFs negotiating contracts and all persons having requested copies of their price offers.

4. A QF or utility which signs an initial offer may not modify such offer until the term of the resulting contract expires. Any later modifications made by the Commission to the utility offers will be prospective only and will not alter the terms of the initial offer.

5. A QF which has contracted with the utility after May 19, 1981, and before the filing of the initial offers may modify its contract to conform to the standard contract adopted by the Commission after evidentiary hearing.

6. Utility offers for as-available energy and capacity shall, among other things:

a. differentiate payments to QFs by time of use

b. pay for capacity in cents per kWh produced

c. include transmission and distribution costs in the aggregate

d. include costs or savings from line losses in the aggregate

e. recognize the aggregate capacity value of QFs

f. base capacity payments on 100% of the annual capacity value of each utility's estimate of current shortage costs

7. Each utility shall file annual capacity payments differentiated by time of use based on the 1982 estimated cost of peaking capacity.

8. Utility offers for *firm energy* and capacity shall, among other things:

a. allow QFs the option of receiving avoided cost energy payments at the time of delivery or at the time the contractual obligation is incurred.

b. include the value of (1) availability during system peak periods, (2) dispatchability, (3) contract duration, termination, and sanctions, (4)

scheduling of outages, and (5) availability during emergencies, and shall be comparable to performance standards the utility would impose on its own plants.

c. base capacity on the avoided (marginal) capacity cost used in each utility's last general rate case.

d. include transmission and distribution costs in the aggregate

e. include costs or savings from line losses in the aggregate

f. base the aggregate capacity value for hydro on the average of five dry years, or on other alternatives discussed in the decision.

9. Within 90 days of the effective date of this order each utility shall file by application served upon all parties, a standard offer based on a forecast of energy payments for up to five years. This option shall be available to all QFs.

10. Within 90 days of the effective date of this order, each utility shall file, by separate application served upon all parties, a standard offer for long-term firm capacity based on each utility's resource plan. Long-run marginal cost estimates shall include all fixed costs associated with each utility's resource plan, and system marginal operating costs.

11. Each utility shall file, within 45 days of the effective date of this order, by application served upon all parties, simplified standard offers for QFs below 100 kW in size. Payment for energy and capacity shall be expressed in terms of cents per kWh and shall be offered on either a time-or nontime-differentiated basis. Capacity payments on a nontime-differentiated basis shall be 50% of the annual capacity value of each utility's estimate of current shortage costs.

12. Standard offers shall allow QFs to convert to and from simultaneous purchase and sale. However, such conversions shall be limited to once per year. The option to convert from simultaneous purchase and sale to sale of surplus shall not be available to a QF which chooses the forecasted energy payment option under either an as-available or long-term contract.

13. All payments made by utilities to QFs under the standard offer and approved nonstandard contracts shall be subject to recovery: in ECAC or other appropriate proceedings.

14. Utility purchases are not required from QFs during periods when the utility's avoided cost is negative, as defined in the decision.

15. Utilities shall, whenever possible, notify QFs of the possibility that purchases may be refused, with a minimum of 48 hours notice to QFs with baseload or intermediate plants, and a minimum of two hours notice to QFs with peaking plants.

16. Curtailment for reason of nonpurchase shall be for QFs of 1 MW or larger only, and shall occur in the following order:

a. Small power producers who can inventory fuel;

b. Topping cycle cogenerators who can bypass the electric generation and save some fuel; and

c. Bottoming cycle cogenerators and small power producers.

17. Each utility shall file annually a report regarding periods during which purchases were refused for the previous year. Utilities subject to ECAC shall file in conjunction with their annual reasonableness review. PP&L shall file yearly, beginning January 31, 1983.

18. Existing standby rates shall be extended to all QFs with demand schedules. Standby charges shall be waived where the QF attains an 85% capacity factor in a given month.

Each utility shall file within 45 days alternate standby rates with a three-month ratchet for QFs on time of use rates.

19. PP&L, Sierra, and CPN shall file standby rates which recognize the seasonal operations of certain QFs in their service areas. Such rates shall provide for a three-month demand ratchet.

20. Edison and SDG&E shall expand their current interruptible service offerings to cover all QFs above the current 500 kW minimum. PG&E shall offer similar interruptible service to QFs to the extent that interruptible rates are filed for all large customers.

PP&L, Sierra, and CPN shall provide interruptible service to large QFs on a contractual basis.

21. Each utility shall file with its standard offer interim parallel generation tariffs which specify interconnection reliability and safety requirements. These tariffs shall incorporate the functional standards adopted in this decision. The tariffs shall specify separate guidelines for QFs below 100 kW, between 100 kW and 1 MW, and above 1 MW.

A QF shall have the option of owning, operating, and maintaining the interconnection equipment, or paying the utility to do so.

22. Utilities shall require QFs to pay for interconnection costs. The QF shall be granted the option either to: (1) advance to the utility the estimated cost of the interconnection facilities and also pay a monthly charge as authorized by the Commission, or; (2) not advance such additional costs and pay a monthly charge as authorized by the Commission. The QF shall pay a facility termination

charge defined as the estimated installed cost, plus the estimated removal cost, less the estimated salvage value for interconnection facilities to be removed. The utility shall deduct from the termination charge the advance previously paid, if any. If the advance paid is greater than the termination charge, the utility shall refund the difference without interest to the QF.

23. Each utility shall file a report beginning January 31, 1983, indicating the extent of wheeling performed during the previous year. Such report shall name the parties for whom wheeling was performed, include the terms and conditions, and technical arrangements of the transaction, and describe the status of any pending requests to wheel. The report shall also describe the circumstances relating to any wheeling request which was refused.

24. Nonstandard contracts shall be reviewed in the manner set forth in this decision. Advance review of such contracts shall cease two years from the date of this order, unless the Commission extends it further.

25. The standard offer shall be available to all QFs for acceptance and shall be consistent with the terms and conditions provided for in this decision. It shall remain in effect until further order of this Commission.

26. PP&L shall be exempt from filing the standard price offers ordered in this decision. Instead, PP&L shall file a standard price offer based on avoided cost principles, which is consistent with its operations. Such filing shall be made by application within 45 days from the effective date of this order and shall be served upon all parties to this proceeding.

27. Sierra shall be exempt from filing standard price offers for QFs over 100 kW

28. Each utility shall bargain in good faith with QFs.

29. Each utility shall undertake outreach efforts to assure all potential QFs are aware of opportunities available

pursuant to this order. Particular emphasis should be placed on notice to small business and minority organization.

This order is effective today.

Dated January 21, 1982, at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
Commissioners

Commissioner Priscilla C. Grew present but not participating.

APPENDIX A

LIST OF APPEARANCES

Respondents: *Robert Ohlbach* and David L. Ludvigson, Attorneys at Law, for Pacific Gas and Electric Company; *Eucene Wagner,* Attorney at Law, for Southern California Edison Company; Stoel, Rives, Boley, Fraser & Wyse, by *Thomas Nelson,* Attorney at Law, for Pacific Power & Light Company; *Margaret Sullivan,* Attorney at Law (Colorado, Iowa), for San Diego Gas & Electric Company; and *John Vetromile,* for CP National.

Interested Parties: *Laura B. King,* for the Natural Resources Defense Council (NRDC); Morrison & Foerster, by *Alan Cope Johnston,* Attorney at Law, for Great Western Malting Company/Windfarms, Ltd.; *Robert W. Schempp,* for The Metropolitan Water District of Southern California; Hanna & Morton, by *R. Lee Roberts,* Attorney at Law, for Occidental Geothermal, Inc.; *John Curtis Lakeland,* for Mass-Production Systems; *Matthew V. Brady,* Attorney at Law, for the California Energy Commission; *Harry K. Winters,* for the University of California; *Harvey M. Eder,* for Public Solar Power Coalition; Miller, Balis & O'Neil, by *Robert A. O'Neil,* Attorney at Law (Massachusetts, District of Columbia), for the City of Alameda (Bureau of Electricity); *Bryan Gross,* for South San Joaquin and Merced Irrigation Districts; *C. Hayden Ames,* Attorney at Law, and Carthrae M. Laffoon, for Geothermal Generation, Inc.; P. R. Mann & Associates, by *Philip R. Mann,* Attorney at Law, and Robert E. Burt, for the California Manufacturers Association; *James W. Gruebele* and Gray Olsen, for the Dairyman's Cooperative Creamery Association; *Bert Brook,* for the Hudson Lumber Company; *C. Edward Taylor,* for Louisiana-Pacific Corporation; *Donald Hardy, for Pan Aero Corporation; Randall*

Tinkerman, for Transition Energy Projects Institute; *Burton J. Gindler,* Attorney at Law, for Kelco; McDonough, Holland & Allen, by *Bruce McDonough,* Attorney at Law, for San Bernardino Valley Municipal Water District; *Harry Davitian,* for San Diego Energy Recovery (SANDER) Project; *David K. Takashima,* for Agricultural Council of California; *Mark Henwood,* for Henwood Associates, Inc.; *Neil K. Holbrook,* for Power Towers, Inc.; *Frank Hodgson,* for Hans W. Wynholds Company; *J. C. Solt,* for Solar Turbines, Inc.; Latham & Watkins, by *David L. Mulliken,* Attorney at Law, for Solar Turbines International; Michael McQueen, Attorney at Law, for Union Oil Company of California; and *Otto J. M. Smith* and *Kenneth R. Meyer,* for themselves.

Commission Staff: *Sara Steck Myers, Ellen LeVine,* and *Brian T. Cragg,* Attorneys at Law, and *John Quinley.*

(Notice: This glossary is intended to aid the reader in understanding this decision. Legally binding definitions must be derived from the context of the decision and applicable FERC rules.)

GLOSSARY

AGGREGATE VALUE - The value of electricity production to the entire utility system as opposed to more local conditions, e.g. avoided transmission and distribution costs may be aggregated over the utility's entire system and paid to a QF on a prorated basis without regard to its distance from the load center.

AS-AVAILABLE ENERGY/CAPACITY - Electricity provided by a QF to a utility as it becomes available, rather than at prearranged times and in prearranged quantities.

AUXILIARY POWER SOURCES (APS) - Electric generating facilities designed to be used in the event of an outage on the local utility grid.

AVERAGE COST PRICING - The pricing of electric service designed to recover the total costs on a system in order to make total revenues (including rate of return) equal to total costs. Total costs are based on costs as recorded in books of account and forecasted to be recorded in such accounts.

AVOIDED COSTS - The incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

BACK-UP POWER - Electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

BASELOAD - The minimum continuous load on a power system over a given period of time.

BIOMASS - Any organic material not derived from fossil fuels.

BIOMASS CONVERSION - The process of conversion of any organic material not derived from fossil fuels (such as wood waste, rice hulls, walnut shells, etc.) into electricity or energy.

BOTTOMING-CYCLE COGENERATION FACILITY - A cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used for power production.

CAPABILITY - The maximum load which a generator, turbine, transmission or circuit, apparatus, station, or system can supply under specified conditions for a given time interval without exceeding approved limits of temperature and stress.

CAPACITY - The load for which a generator, turbine, transformer, transmission circuit, apparatus, station, or system is rated. Capacity is also used synonymously with capability.

CAPACITY COSTS - Those costs associated with capital investments in electricity production and delivery.

CAPACITY FACTOR - The ratio of average load on a generating resource to its capacity rating during a specified period of time expressed in percent.

CAPACITY PAYMENTS - Those payments which reflect the value capacity received.

COGENERATION - The sequential production of electricity and heat, steam, or useful work from the same fuel source.

COGENERATION FACILITY - Equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial heating, or cooling purposes, through the sequential use of energy.

COMBINED CYCLE - Waste heat from a gas turbine topping cycle is utilized for the generation of electricity in a steam turbine/generator system, thereby increasing the efficiency of heat utilization.

CURTAILMENT - A period during which a utility declines to purchase available electricity from a QF, generally due to low demand or system maintenance requirements.

DEBT SERVICE - Periodic payments due on loans made to a QF.

DISPATCHABILITY - That condition of the qualifying facility whereby, through engineering design, installed equipment, operating conditions, and procedures, the electric utility has the ability to dispatch the facility for operation at any time, in a manner agreed upon by the parities.

ECAC (ENERGY COST ADJUSTMENT CLAUSE) - Periodic adjustments of utility rates to reflect fuel and related costs.

ENERGY COSTS - Those costs associated with fuel use in electricity production.

ESCALATED PAYMENTS - A payment commitment for future years determined from forecasted rates of avoided costs.

FIRM CAPACITY PAYMENTS - Payments for electricity provided in predetermined quantities and at predetermined times, which may be based on avoided costs at time of delivery or at the time the obligation is incurred.

FIRM POWER - Power available at all times during the period covered by the commitment, except for forced outages and scheduled maintenance. Firm power is provided with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller and less expensive plant, or to purchase less firm power from another facility.

FORECAST - Future values determined by a mathematical model.

HEAT RATE - A measure of generating station thermal efficiency generally expressed as Btu per net kilowatt-hour. The average heat rate is computed by dividing the total Btu content of the fuel burned by the resulting net kilowatt-hours generated. The marginal heat rate is calculated as the additional (saved) Btu's to produce (not produce) the next kilowatt-hour.

INCREASE IN SUPPLY - An economic model of electrical production by QFs whereby such production is viewed as increasing aggregate supply of energy, implying that QFs should be subject to operating and performance standards comparable to a utility's own generating plants for purposes of determining pricing.

INTERCONNECTION - The physical system of electrical transmission between the QF and the utility.

INTERCONNECTION COSTS - The reasonable costs of connection, switching, metering, transmission, distribution safety provisions, and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

INTERRUPTIBLE POWER - Electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

KILOWATT (kW) - An electrical unit of power which equals 1,000 watts.

KILOWATT-HOUR (kWh) - A basic unit of electrical energy equal to the use of 1 kilowatt for a period of one hour.

LEVELIZATION - A financial arrangement whereby payments are constant over a specified period and are based on forecasted values and the value of money over time.

LINE LOSSES - Losses in electricity which occur during its transmission and distribution.

LOAD - The amount of electric power delivered to a given point on a system, or total amount of demand on the system.

LOAD FACTOR - The ratio of average to peak use during a specified period of time, expressed in percent.

LOAN OR BOND GUARANTEES - A utility liability which guarantees the repayment of a bond or loan on behalf of a QF in the event that the QF is unable to make timely payments.

MAINTENANCE POWER - Electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

MARGINAL COST PRICING - The pricing of electric service designed to equate the rates for electric service with the marginal costs of that electric service.

MARGINAL COST - The change in total cost caused by a change in output. Marginal cost can also be understood as the additional cost to produce an additional unit of output, or the savings from producing one unit less of output (i.e. avoided cost).

MONOPOLY - A market structure in which there are many buyers but only one seller.

MONOPSONY - A market structure in which there are many sellers and only one buyer.

NATURAL GAS - Either natural gas unmixed, or any mixture of natural gas and artificial gas.

NONFIRM POWER - Electric power available as surplus only, which is supplied by the power producer at the producer's option and can be interrupted by the power producer at will.

NONSTANDARD CONTRACTS - Negotiated contracts between utility and a QF which do not conform to standard offer guidelines previously approved by the CPUC.

OIL- Crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products.

PEAK LOAD - The maximum electric load consumed or produced in a stated period of time. It may also be char-

acterized as the minimum instantaneous load within a designated interval of a stated period of time.

PURCHASE - The purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

QUALIFYING FACILITY - A cogeneration facility or a small power production facility which is a qualifying facility under 18 CFR, Chapter I, Part 292, Subpart B of the FERC regulations.

RATE - Any price, rate, charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.[1]

RATE BASE - The utility investment on which the utility is allowed to earn a rate of return.

REDUCTION OF DEMAND - An economic model of electrical production by QFs whereby such production is viewed as reducing aggregate demand for energy, implying that QFs need not be subject to utility operating and performance standards for purposes of pricing determinations.

REFUSAL TO PURCHASE - See curtailment.

REFUSE-DERIVED FUELS - Fuels derived from municipal waste used as fuel for electric energy production or low Btu gases from sewage treatment plants for use in turbines.

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[1] Rates are defined in the California Public Utilities Code to include rates, fares, and charges (§ 210). § 451 of the Code identifies rates as all charges demanded or received by any public utility for a product or commodity furnished. We recognize the FERC definition of rate to include any price for purchase and use the term rate herein to refer also to prices. However, the term price is also used in this report to allow for a separate identification, in some cases, of payments for purchases from the more traditional use of the term rates as referring to charges demanded or received under filed tariffs.

RELIABILITY - In the context of the decision, the reliability of a QF to the electrical utility and to the system, which may be determined by a specified set of standards.

RESERVE MARGINS - Extra capacity available to: (1) meet anticipated demands for power; (2) serve load in the event of a loss of generation resulting from an unscheduled outage. Reserve margin is the ratio of excess capacity to anticipated peak load expressed as a percent.

SALE - The sale of electric energy or capacity or both by an electric utility to a qualifying facility.

SIMULTANEOUS PURCHASE AND SALE - A regulatory convention that allows a QF to simultaneously sell its own generation to the utility while purchasing its requirements from the utility; an exchange of electrical flow does not necessarily occur - the difference is cash flow.

SMALL POWER PRODUCTION - Any unregulated electricity production facility as defined primarily in the FERC rules, including hydroelectric facilities, geothermal, biomass refuse-derived fuel, and wind facilities.

SOCIAL COSTS - Tangible but hard-to-quantify costs to society of an economic or technological activity.

SPINNING RESERVES - Reserves that are operated at less than the rated capacity to relieve imbalance on the system.

STANDARD OFFER - A utility offer to purchase electricity from a QF that is formed within guidelines previously adopted by the CPUC.

SUPPLEMENTARY FIRING - An energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility.

SUPPLEMENTARY POWER - Electric energy or capacity supplied by an electric utility, regularly used by a qual-

ifying facility in addition to that which the facility generates itself.

SYSTEM EMERGENCY - A condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

SYSTEM POWER VALUES (SPV) - PG&E's model of the marginal costs of additional capacity and energy, based in Application 58545, OII 26, and PG&E price offers on a combined cycle plant as the marginal plant.

TIME DIFFERENTIATED PAYMENTS - Payments made according to time-of-day or time-of-year delivery periods.

TOPPING-CYCLE COGENERATION FACILITY - A cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy.

TOTAL ENERGY INPUT - The total energy of all forms supplied from external sources other than supplementary firing to the facility.

TOTAL ENERGY OUTPUT OF A TOPPING-CYCLE COGENERATION FACILITY - The sum of the useful power output and useful thermal energy output.

UP-FRONT PAYMENTS - Initial large outlays provided to QFs by utilities to assist in financing large capital expenses incurred for construction.

USEFUL POWER OUTPUT OF A COGENERATION FACILITY - The electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.

USEFUL THERMAL ENERGY OUTPUT OF A TOPPING-CYCLE COGENERATION FACILITY - The thermal energy made available for use in any industrial or

commercial process, or used in any heating or cooling application.

VALUES TO PERPETUITY - The costs (values) of owning and operating a generating plant for an infinite number of years, assuming plant replacement at the end of its useful life. Values are then levelized to the initial year.

WASTE - By-product materials other than biomass.

WHEELING - The use of transmission facilities of one utility system to transmit power to another utility system or between customer facilities within a single utility system or between utility systems.

Decision 82-12-120 December 30, 1982

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision 82-02-103 in Order Instituting Rulemaking No. 2.	Application 82-03-26 (Filed March 8, 1982)
SOUTHERN CALIFORNIA EDISON COMPANY, application for 3 standard offers for purchase of electric power from cogeneration and small power production facilities.	Application 82-03-37 (Filed March 8, 1982)
Application of SIERRA PACIFIC POWER COMPANY, for approval of its standard offer to purchase cogeneration and small power production facilities.	Application 802-03-62 (Filed March 16, 1982)
Application of PACIFIC POWER & LIGHT COMPANY for Approval of Certain Standard Offers Pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-03-67 (Filed March 18, 1982)

In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for an Order by the California Public Utilities Commission Directing SDG&E to Purchase Power From Qualifying Facilities Based on Standard Offers and to Make Certain Changes or Additions to its Tariffs Affecting Purchases from Qualifying Facilities.	Application 82-03-78 (Filed March 22, 1982)
Application of CP NATIONAL CORPORATION for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-04-21 (Filed April 8, 1982)
Rulemaking on the Commission's own motion to establish standards governing the prices, terms, and conditions of electric utility purchases of electric power from cogeneration and small power production facilities.	OIR 2 (Petition for Modification filed September 10, 1982)

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OPINION

Summary

Decision (D.) 82-01-103, January 21, 1982, established guidelines for utility purchases of electricity from cogenerators and small power producers. That decision ordered utilities to file five standard price offers each of which would be a complete contract which small power producers could sign without negotiation. The five offers were to meet the varied needs of different qualifying cogeneration and small power production facilities (QFs).

* The *as-available* offer pays an energy payment and a capacity payment in ¢/kWh varying by time of delivery. The payment is derived from utilities' short-run avoided costs (i.e., variable operating costs plus shortage value). This offer is similar to a spot market purchase in a competitive environment and requires no long-term contract-type commitment on the part of the QF.

* The *firm capacity* offer is like the as-available except that payments for capacity are based on specific performance requirements being met by the QF (including *availability* or *output* requirements). The capacity price may be fixed for up to 30 years. The offer provides some pricing certainty for those who can meet the specific performance criteria.

* The *less than 100 kW* offer is similar to the as-available, except for simplified requirements for the small facilities.

* The *five-year forecast* offer fixes energy prices for five years, providing more price certainty.

* The *long-term resource plan* based offer bases prices on new utility resources (as opposed to

short-run avoided costs). It may be used to establish price more firmly for longer periods and to pay for the full value of new resources.

The first three offers, as filed by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) are the subject of this decision. The utilities' standard contracts, as filed with the Commission, were reviewed during 40 days of compliance hearings in which the utilities, Commission staff (staff), and QFs participated. This decision responds to the various objections of the parties regarding pricing and standards for performance. It does not address all the issues raised in the proceeding. The remaining issues (interconnection, filing requirements, miscellaneous contract terms, insurance, and others) will be the subject of a later decision.

Given the policy of trying to create standard contracts which can be signed directly, the Commission reviewed all of the details relating to pricing and standard offer terms. The following is a summary of the specific issues addressed and resolved in this decision:

* *Payments for Capacity.* The decision adopts the full cost of a combustion turbine for capacity for long-term contracts signed at this time. It concludes that refinements to this methodology may be appropriate in the future.

* *Performance Requirements.* Regarding the specific performance requirements necessary to obtain firm capacity payments, the decision generally adopts PG&E's proposal which bases firm capacity on either *availability* (a QF agrees to produce when called upon) or *output* (a QF agrees to provide energy during 80% of a summer peak period). The QF has a choice. The proposal by Edison, on the other hand, is rejected, and the utility is asked to amend its

offer consistent with PG&E's approach, as modified by this decision. Edison's proposal, by combining both availability and output in one package, is found to be too burdensome and not in compliance with D.82-01-103. SDG&E's two offers are both found not to be in compliance. SDG&E is also directed to amend its offer consistent with PG&E's offer, as modified by the decision.

* *Termination Provisions.* In the event a firm contract QF terminates, the decision finds that the QF must repay the amount it was paid that exceeded what it would have been paid had it not signed a long-term contract (the levelization overpayment). Additional provisions are established if inadequate notice is given. This approach basically follows that used by PG&E and SDG&E. Edison's reimbursement calculation is approved, but Edison is otherwise required to modify its approach in keeping with the decision.

* *Energy Payments.* The decision establishes a procedure which allows QFs to review and comment on the utilities' proposed energy rates filed each period. It also orders the utilities to include contract language which clarifies that energy payments shall be derived from the full avoided variable operating costs throughout the life of the contract. Individual issues are also resolved regarding use of average vs. actual year incremental heat rates in the calculations (average is used now, but utilities can make proposals for actual later), line loss (such losses are assumed to be similar to utility plants, but further study is requested), and curtailment (the system established in D.82-01-103 is con-

tinued with a rejection of limits on the use of this provision for now).

Introduction

This decision represents a further step by this Commission toward its stated goal of promoting the development of cogeneration and small power production facilities, alternatives to the traditional generation of electric power through the use of fossil fuels. Our policy, developed in previous decisions, will be served by this order's clarification and further definition of the proper relationship between public utilities and these alternate generation resources.

To date, the most significant proceeding in this regard has been Order Instituting Rulemaking (OIR) 2. OIR 2 was commenced to establish standards governing the prices, terms, and conditions of utility purchases of power produced by qualifying cogeneration and small power production facilities (qualifying facilities or QFs). The proceeding was stimulated by our own independent action and analysis, as well as the requirements of both state law (Public Utilities (PU) Code § 2821) and federal law (the Public Utility Regulatory Policies Act of 1978 (PURPA)). PU Code § 2821 requires the Commission to "approve and establish equitable charges" to be paid to privately owned generation facilities. PURPA and the resulting regulations adopted by the Federal Energy Regulatory Commission (FERC) specify rules governing a public utility's purchase of power from cogenerators and small power producers who qualify for the benefits of the law. The FERC regulations require state implementation.

On January 21, 1982, we issued D.82-01-103 in OIR 2. The decision ordered the major California electric utilities to file standard offers for power purchases from qualifying facilities based on avoided cost principles. We concluded that avoided cost pricing would promote the maximum efficient development of these alternative resources.

The standard offer ordered by D.82-01-103 was intended to describe not only the prices to be paid to QFs, but the rights and obligations corresponding to those prices. The standard offer is, in other words, an economic package in which the prices and the contract terms are inextricably bound together.

In order to meet the varied needs of QFs, the standard offer, designed to recognize the two basic components of a power purchase - energy and capacity, provided five different options. The options, expressed as separate offers, were further distinguished by the time within which they were required to be filed by the utilities. A shorter time frame was assigned to those offers which we felt could be reviewed more expeditiously. The offers and filing periods were as follows:

1. Within 45 days of the effective date of D.82-01-103, the utilities were ordered to file standard offers for:

    a. As-available energy and capacity based on a short-run avoided cost methodology.

    b. Firm capacity based on a short-run marginal cost methodology.

    c. Energy and capacity provided by QFs below 100 kilowatts (kW) in size.

2. Within 90 days of the effective date of D.82-01-103, the utilities were ordered to file standard offers for:

    a. Energy based on a forecast of energy payments for up to five years tied to either an as-available or firm capacity option.

    b. Firm capacity based on a utility's long-run marginal costs developed from the utility's resource plan.

The scope of the present proceeding is limited to those offers for which a 45-day filing was set in D.82-01-103, as listed under item 1. above. Five-year forecasted energy payments and long-term firm capacity offers will be reviewed in subsequent proceedings (Application (A.) 82-04-44, A.82-04-46, and A.82-04-47).

In D.82-01-103, the Commission outlined the procedure which would be followed in the approval of the offers filed after 45 days. Following staff review, the offers were to take effect two weeks after the date of filing unless otherwise suspended by the Commission. Each of these offers would then be reviewed in subsequent evidentiary hearings to determine the utility's compliance with D.82-01-103 and the factual basis for the prices contained in the offers. By D.82-04-071 (April 12, 1982), a subsequent order modifying D.82-01-103 and denying rehearing, all utilities were required to amend their initial filings to conform to the prescribed modifications and cure specific deficiencies identified in D.82-04-071. The presently effective offers were filed in May and July 1982.

Procedural Background

A. Prehearing Matters

Compliance hearings as required by the Commission in D.82-01-103 commenced with a prehearing conference held on May 10, 1982, in San Francisco, California. At that time, the presiding administrative law judge (ALJ) announced that at page 144 of D.82-01-103 the Commission had prescribed the scope of the hearings as follows:

> "These evidentiary hearings. . .will be narrowly restricted to the issues of each utility's compliance with the requirements of this decision and of the factual basis for the prices contained in each standard offer. The evidentiary proceeding will *not* be a forum for reexamining the issues resolved in this decision." (Emphasis original.)

During the prehearing conference, however, it became clear that, even with this limitation on the hearings, there remained numerous issues related to both the utilities' compliance with D.82-01-103 and subjects not resolved by that decision but relevant to the standard offers. More than 25 parties voiced their concerns and offered suggestions with how to proceed in this complex matter.

Based on statements made at the prehearing conference and subsequent written statements filed by applicants and the staff on May 14, 1982, an ALJ ruling was issued on May 19, 1982. The ruling included the following determinations:

1. To initiate hearings, the completion of staff reports related to the applications of Edison (A.82-03-37), PG&E (A.82-03-26), and SDG&E (A.82-03-78) were necessary. Several of the applicant utilities had argued that their applications were intended to comply with the orders issued in OIR 2. Therefore the response of staff or interested parties to those filings were required in order to identify the issues.

2. Following receipt of staff's report on Edison, public hearings would commence on July 12, 1982, with Edison's direct showing.

3. Hearings on the applications of Sierra Pacific Power Company (A.82-03-62), Pacific Power & Light Company (A.82-03-67), and CP National Corporation (CP National) (A.82-04-21) would be deferred until staff reports could be issued on those applications.

4. The ALJ concurred with the staff that issues to be considered in this proceeding extended to questions dealing with provisions included in the utilities' applications, although not specifically addressed by the Commission in its

OIR 2 decisions, as well as an applicant's compliance with those orders.

5. The tariffs required by D.82-01-103, Ordering Paragraphs 18 and 19 (standby rates) and Ordering Paragraph 21 (parallel generation), should be considered an integral part of the subject standard offers for purposes of assessing their compliance with OIR 2 and must therefore be made part of each of the subject applications.

B. Hearings

1. Expert Testimony

Following this ruling, 40 days of hearing were held between July 12, 1982 and October 15, 1982, in San Francisco. During that time, testimony was presented relating to the applications of PG&E, Edison, and SDG&E. Between the applicant utilities, the Alternate Generation and Rate Design Sections of the staff, state and local government agencies, and businesses and individuals presently or potentially operating or involved with cogeneration and small power production facilities, a total of 41 witnesses were called to testify. Many of these witnesses, who included experts in engineering, economics, law, and management, testified more than once during the hearings. Interested parties, representing various types of QF development, accounted for 17 of these witnesses. Seventy-four exhibits were received into evidence.

2. Statements

During the course of the proceeding, a number of individuals had expressed their desire to offer statements, as opposed to testimony, during hearing. In response to these requests, the ALJ, in noticing the hearing dates to be reserved for the testimony of interested parties, also set a specific date for public statements.

On August 30, 1982, 18 people offered their views relating to the standard offers at issue. These individuals were uniformly concerned that various provisions of the utilities' standard offers were not in keeping with this Commission's and PURPA's policy of encouraging the development of qualifying facilities. In particular, these individuals questioned the utilities' bases for the calculation of their avoided costs and the reasonableness of certain provisions of the standard offers which they considered to be penalties or obstacles to QF development.

Most of those making statements either were purchasers or sellers of small, home-sized (1 to 10 kW) and wind generators. Their chief concern was the level of insurance required of QFs under the standard offers. It was argued that the premium level exceeded both the revenue benefit to be derived from installation of a wind generator as well as any risk created by such a facility. All agreed that the present insurance requirements would stifle the growing potential of this alternate resource.

In addition to these statements, other individuals either took the opportunity during other regularly scheduled hearing days to make statements or wrote letters to the Commission on the subject. These statements and correspondence, which were most frequently industry-specific, raised concerns similar to those expressed in other testimony and comments and asked the Commission to adopt standard offers which would encourage, not discourage, QF production.

C. Consideration of Firm Capacity Methodology

During the hearings PG&E and Edison attempted to offer testimony and question the staff on the proper methodology for determining the as-available capacity and firm capacity prices to be paid to QFs. By oral ALJ ruling on July 20, 1982, all parties were precluded from addressing this issue on the grounds that the issue had been resolved in OIR 2 and was beyond the scope of these compliance

proceedings. This ruling was based on a review of the language of D.82-01-103 and D.82-04-071 in OIR 2 and consultation with the assigned Commissioner's office. On July 26, 1982 PG&E filed a motion with the Commission seeking reversal of this ruling. Edison filed a similar motion on July 29, 1982.

The assigned Commissioner concluded that this matter did not need to be referred to the Commission, but rather should be resolved by further ALJ ruling. Upon consideration of the petitions of PG&E and Edison and further review of the applicable Commission decisions, it was determined that the ALJ's ruling should be reversed in part and affirmed in part. Specifically, it was concluded that this proceeding was the proper forum for addressing the issue of the appropriate methodology for determining capacity costs, based on the shortage cost concept, under a utility's firm capacity standard offer. Revision of the methodology for calculating a utility's as-available capacity payment adopted in D.82-04-071, however, was reserved for the utilities' general rate cases as specified in that decision.

Testimony by all parties on the issue of the proper methodology for calculating a utility's firm capacity price was heard over a 10-day period following the presentation of all other testimony. In order to expedite the submission of this matter, certain information proposed by PG&E relating to this issue was directed to be served on the parties after the final day of hearing.

D. Submission

At the conclusion of the final day of hearing on October 15, 1981, and in an ALJ ruling issued that same date, A.82-03-26, A.82-03-37, and A.82-03-78 were submitted upon the following:

1. The submission by PG&E of an additional proposal and adjustment related to the Energy Reliability Index used by PG&E in calculating

its shortage costs on which PG&E's standard offer for firm capacity will be based.

2. The filing of concurrent briefs on November 15, 1982.

PG&E was directed to serve its proposal on all appearances in this proceeding. Any party wishing to address or request a hearing on this proposal was directed to do so in the briefs due on November 15. Requests for hearing were to include a specific identification of the basis for the request and any questions to be addressed in cross-examination.

On the final day of hearing, SDG&E was also directed to furnish a copy of its input assumption data to staff, which had formally requested it on October 15, and to the State Energy Task Force, prior to the end of the briefing schedule. According to the briefs, this material had not been received by that time.

On October 25, 1982, PG&E filed its proposal. PG&E also submitted on November 2, 1982, a recalculation of its annual Energy Reliability Index adjustment factors based on a "low" load management scenario.

Between November 15 and 17, 1982, concurrent briefs were filed by a total of 16 parties including PG&E, Edison, SDG&E, staff, the Independent Energy Producers (IEP), the California Manufacturers Association (CMA), Occidental Geothermal, Inc. (Occidental), Ultrasystems, Inc., Federal paper Board Company, Inc., the Regents of the University of California (UC), Calcogen, Inc., the California Energy Commission (CEC), the State Energy Task Force, the California Waste Management Board, Kimberly-Clark Corporation, and Simpson Paper Company. Any delays in filing were attributable to breakdowns in required support systems. Correspondence was also received at that time addressing issues similar to those presented in the briefs.

Positions of the Parties

The testimony received during hearing in this proceeding was sponsored by numerous witnesses representing a variety of interests, including those of the applicant utilities, government, and private industry. The views of 16 of the appearances regarding this record have been expressed in concurrent briefs. Other parties, although providing testimony, have chosen not to file briefs, in some cases apparently due to a lack of economic resources. Still others have addressed the issues raised during hearing in correspondence to the Commission. To provide an overall description of the parties' basic viewpoints, we have summarized the positions below.

A. Utilities

All three utilities, PG&E, Edison, and SDG&E, believe that their applications are in full compliance with this Commission's decisions in OIR 2. Each asserts that the record fully supports this conclusion.

The utilities are also of the opinion, however, that to promote the continued development of QF power, certain amendments to their standard offers may be desirable. Each utility asks that it be recognized that any suggested modifications of its standard offers do not result from a failure to comply with OIR 2, but rather are aimed at better achieving the goal of QF development.

According to their briefs, the determination or adoption of any standard offer amendment by a utility was greatly influenced by the utility's perceived responsibility to its ratepayers. The utilities believe that the PURPA mandate requiring prices paid for QF power to be just and reasonable to ratepayers is embraced in the concept of avoided cost. Under that concept, the utility is to pay the QF a price equal to the cost the utility would have incurred had it generated the electricity itself or purchased the power elsewhere. The ratepayer should therefore remain indifferent to whether the utility or the QF produces the power.

This principle of ratepayer indifference has led the utilities to conclude that a standard offer must result in a proper allocation between QFs and utilities of the risks associated with the transaction. Should business and economic risks be shifted to the utility and its ratepayers disproportionate with the benefits to be received from QF production, a ratepayer would no longer remain indifferent since that risk would ultimately be translated into additional costs to the ratepayer.

The utilities' briefs also reflect the view that the standard offer is a single, integrated economic package. SDG&E specifically advises that the division of issues in its brief is arbitrary since all of the standard offer provisions relate to price in one way or another.

B. Staff

The staff states that its primary concern is whether or not the utilities' standard offers comply with this Commission's decisions in OIR 2. Staff is of the opinion, however, that to develop effective standard offers the issue of compliance should include an examination of (1) the propriety of contract terms which the Commission has yet to direct be included or excluded from the standard offers, (2) the determination of a utility's true avoided costs, and (3) the need for standardization of contract terms between different utilities' standard offers.

Like the utilities, the staff's recommendations are intended to achieve the proper balance of ratepayer and QF interests. The risks associated with the standard offers, however, are viewed somewhat differently by the staff than by the utilities. In particular, the staff notes that the QF market is still in its infancy. This circumstance has two results - the need for continued encouragement for its development and an increase in the risks which potential investors and owners perceive are associated with a QF's operations. It is the staff's belief that ratepayers who will benefit from the increased development of alternate

energy resources should share in the risks related to this emerging industry.

C. Private Industry

This category includes a total of eight parties representing the interests of currently operating or potential QFs. Among these parties were two associations: IEP, representing a group of California cogenerators, small power producers, and related businesses, and CMA, representing industries some of whom desire to participate in QF programs and other who do not. Briefs were also filed by Occidental, Ultrasystems, Inc., Federal Paper Board Company, Inc., Calcogen, and Kimberly-Clark Corporation and Simpson Paper Company, who sponsored a joint brief.

The participation of all of these parties has focused on challenges to either the utilities' compliance with OIR 2 or their proposed methodologies for calculating their firm capacity payments, an issue included within the scope of this proceeding. Influencing the positions taken by these parties has been their particular perception of the risks associated with the utility-QF transaction and the proper allocation of those risks. It is the opinion of the industry that to require the QF to bear certain of these risks will ultimately stifle the development which the Commission specifically sought to encourage in OIR 2.

According to these parties, among the risks facing QFs is the inability to obtain financing for projects and predict, on the basis of the contract terms, what each QF can expect in the future. These concerns have been heightened by a substantial drop in avoided cost payments to QFs. This circumstance has jeopardized the operations of current producers and the projects of potential QFs.

Because of this asserted instability in the industry, QFs in their testimony and briefs have been most concerned with the utilities' methods for calculating avoided costs, the availability of data to verify those calculations, the

standards of performance required of QFs, the ambiguity and lack of standardization with respect to certain contract terms, and the utilities' assignment of particular risks to QFs, including the risk of future regulatory changes.

It is the view of the industry that QF production reduces the risks to which ratepayers would otherwise be exposed by utility operations. For this reason, it is the industry's position that QF development should not be stifled by the improper calculation of price, the absence of proper incentives, or a demand for performance which exceeds that of a utility's own plants.

D. State Government

Besides this Commission's staff, briefs were filed by four other state governmental entities: the CEC, the California Waste Management Board, the State Energy Task Force, and UC. With the exception of the CEC, each of these entities is involved directly in the development of alternate generation facilities.

The positions expressed by these parties have been formulated based on a strong desire for the continued encouragement of QF development and for the resolution of problems created by unique arrangements and resources in which the State, in certain cases, intends to be involved. With respect to this latter circumstance, this Commission has been asked to consider the special needs and benefits of projects converting solid waste into energy and the impact on the standard offer of the State itself being a party to or potential beneficiary of the agreement.

Aside from these special concerns, the views of these state entities mirror those held by the QF industry. The utilities' avoided cost calculations are questioned, while standardization of and certainty in contract terms are urged. It is the opinion of state government that its recommendations take into consideration the appropriate allocation of risks between QFs and ratepayers.

E. Positions Expressed in Testimony or Correspondence

The participation of four of the interested parties to this proceeding was limited to the receipt of their testimony; no briefs were filed. These parties included the California Wind Energy Association (CalWEA), which indicated that its financial resources for participation were limited; American McGaw, a manufacturer owning a 2,800 kilowatt (kW) cogeneration facility in California; Henwood Associates, consultants negotiating contracts and arranging financing for QFs; and the County Sanitation Districts of Los Angeles County, the City of Commerce, and the City of Long Beach, local government entities with an interest in waste-to-energy projects.

The sole purpose of the two exhibits sponsored by CalWEA was to challenge the insurance requirements of the utilities' standard offers. Because of the high cost of such insurance and the documented safety of farm- and home-sized wind generators, CalWEA has urged the modification or elimination of the utilities' insurance provisions for wind systems of 20 kW or less. The testimony of the County Sanitation Districts expressed concerns regarding waste-to-energy projects similar to those contained in the testimony and brief of the California Waste Management Board. American-McGaw's testimony covered issues and expressed opinions comparable to those of other industry representatives. Henwood Associates focused on perceived shortcomings in Edison's standard offers.

At the time of submission of this matter, Helmich Engineering, United Energy Corporation, and Hudson Lumber Company wrote to this Commission indicating their views. Mr. James E. Helmich of Helmich Engineering is an appearance of record, while the latter two corporations are members of IEP. Price fluctuation, which in one case has directly affected operations, was the primary concern of these companies. Like other individuals who have written to the Commission during the course of these pro-

ceedings, a resolution of this matter before the end of 1982 was urged to ensure the continued development of the QF industry.

Scope of the Decision

Before commencing our discussion on the issues raised in this proceeding, we must first consider two requests made by several parties regarding the scope and timing of this decision. It is the view of the QF industry that for its development to continue (1) an order resolving all of the issues relating to the subject standard offers must be reached and (2) that order must be issued expeditiously, preferably before the end of 1982. The standard offer is seen as a single, unseverable economic package, the provisions of which must be known before a QF can commence or continue its operations.

Unfortunately, with the extensive participation and record in this matter, the earliest submission data for these applications was November 15, 1982. As a result, we have been left little time to prepare an order which would resolve all of the standard offer issues this year while simultaneously giving the proper weight and consideration to all of the views presented.

For this reason, although we recognize that the standard offer provisions are interrelated, we can address in this decision only certain of the issues arising from those offers. We believe, however, that the subjects chosen, i.e., the basic price issues and certain contract provisions, will provide sufficient options for QFs to make the economic decisions necessary for determining the merits of proceeding with or continuing a particular project.

By adopting this approach, we will be able to consider fully the record which the parties have spent appreciable time and effort developing. All appearances should be assured, however, that those issues which are not discussed in this order will be addressed as early as possible next year.

Specifically, this decision will examine the utilities' bases for and standard offer provisions relating to capacity payments and energy payments. Our discussion of capacity and energy payments will include consideration of such issues as performance requirements, termination, and periods of curtailment. We will also consider the propriety of providing for the conversion of standard offer contracts signed after the effective date of this order to the standard offers approved in our forthcoming second opinion in this proceeding.

Capacity Payments

Because this proceeding was primarily intended to determine the utilities' compliance with our decisions in OIR 2, a basic understanding of those orders, as related to each of the issues to be considered, is critical. With respect to payments for capacity, this Commission concluded in D.82-01-103 that energy delivered on either an as-available or firm basis resulted in a utility avoiding capacity costs. Avoided capacity costs are those costs associated with ensuring the reliability of the production and delivery of electricity which the utility avoids incurring by purchasing power from a qualifying facility.

In OIR 2, the utilities had questioned whether any capacity costs are avoided when energy is delivered to the utility only as it becomes available. D.82-01-103 recognized, however, that as-available power, when aggregated, did in fact result in a reduction in demand upon the utility and thereby avoided certain capacity costs, including those associated with generation and generation-related transmission. Payments for as-available power, however, would not reflect any value for contract length, notice, termination, or sanctions since such provisions would not be part of an as-available offer.

In contrast, firm capacity was viewed as an increase in the utility's supply of electricity with corresponding performance standards, termination provisions, and sanctions.

By definition, firm power is provided in predetermined quantities at predetermined times with sufficient legally enforceable guarantees of deliverability to permit the purchasing utility to avoid the construction of a generating unit or the purchase of firm power elsewhere. A QF providing firm capacity, was determined to avoid costs additional to those related to as-available power. This result was to be reflected in the firm capacity payment.

With respect to the amount to be paid QFs for their output, D.82-01-103 requires "full avoided cost pricing of power from qualifying facilities." (Mimeo, at page 26.) For purchases of both firm and as-available capacity, PG&E, Edison, and SDG&E were directed to base their payments on each utility's estimate of its current shortage costs using a combustion turbine facility as a proxy.

Although recognizing that the combustion turbine was a somewhat less attractive methodology for firm, as opposed to as-available capacity, payments, we concluded in D.82-04-071 that revisions to the adopted methodology would only be considered in the future. For as-available capacity prices, consideration of such revisions was set for the utilities' general rate cases. No specific time, however, was identified for examining modifications of the methodology for calculating firm capacity payments. As stated previously, by ALJ filing, the proper forum was found to be this proceeding.

Because the firm capacity payment should reflect certain factors not included in the as-available capacity price, the following discussion will commence with an examination of the utilities' standard offer terms governing performance and termination in a firm capacity contract. We will then review the methods by which the utilities have calculated the prices to be paid for both firm and as-available capacity.

A. Performance and Termination Provisions in Firm Capacity Contracts

Consistent with the applicable FERC regulations, D.82-01-103 states:

> "The firm capacity payment properly reflects the factors recited in Part IV,A, above related to the availability during system peak periods, including:
>
> "a. Dispatchability,
>
> "b. Reliability,
>
> "c. Contract duration, termination, and sanctions,
>
> "d. Scheduling of outages, and
>
> "e. Availability during emergencies.
>
> "The value of each of these factors shall be calculated, based on standards comparable to performance standards the utility would impose on its own plants. These standards must, however, be fair to QFs and not impose unnecessary burdens that will discourage the development of these preferred resources. The sum of each of these factors and the resultant capacity value will be offered on both a dollars per kW per year and a cents per kWh basis as currently done. A QF that exceeds operating standards normally expected of utility plants should be able to earn a higher capacity payment." (Mimeo, at page 57.)

To aid in the development of standard offers incorporating these basic principles, D.82-01-103 provided further definition of the factors to be reflected in the firm capacity payments. This amplification of each factor can be summarized as follows:

1. *Dispatchability.* According to D.82-01-103, dispatchability is achieved in standard offers by

time basing capacity and energy prices and requiring QFs to maintain availability during peak load periods with a reasonable allowance for forced outages. QFs are to be expected to operate at maximum capacity on notice requiring QFs to maintain availability during peak load periods with a reasonable allowance for forced outages. QFs are to be expected to operate at maximum capacity on notice to meet utility needs for capacity during peak load periods and emergencies consistent with resource limitations.

2. *Reliability.* Reasonable requirements for reliable operation and availability during utility system peak load periods are to be imposed in the standard offers. These requirements, however, should not be unduly restrictive or complicated or impose standards of reliability greater than the utility plants the QF displaces. When resource limitations exist to reliable operations, such as with wind parks, plant capacity factor may be a better measure of reliable operation.

3. *Contract duration, termination, and sanctions.* QFs should be provided the option for levelized capacity payments for periods up to 25 to 30 years. Other than general statements requiring fair contract requirements, the exact terms for provisions relating to termination and sanctions were not specified.

4. *Scheduling of outages.* A utility purchasing firm capacity from a QF may reasonably require the QF to schedule maintenance of that generation during periods established by the utility. The utility must provide reasonable periods for QF scheduled maintenance and only re-

quest deferments in the customer's requested maintenance schedule on 60 days' notice. Capacity payments must not be reduced during scheduled maintenance periods.

5. *Availability during emergencies.* A QF must be expected to operate at maximum capacity on notice to meet utility needs for capacity during emergencies.

Other than our recognition that plant capacity factor, as opposed to availability, might be a better measure of the reliable operation of certain technologies, D.82-01-103 did not endorse any special treatment for specific resources other than small hydro electric facilities. For hydro QFs larger than 100 kW, adjustments for dry year unavailability are to be made in determining the QF's base stream flow and monthly firm capacity rating. A hydro QF would be allowed to use either (1) flow data directly applicable to the QF's facility, when available, or (2) the flow data for the area closest and most similar to the QF's facility, using areas sufficiently limited in size so that the true value of local areas would not be lost or obscured. The minimum June through August flow, from which the monthly firm capacity rating was to be derived, would be based on the five lowest flow years taken from a 50-year minimum continuous record. If this data could not be developed, utilities and QFs would agree upon a shorter time period with fewer minimum flow years averaged into a monthly capacity rating. For both options, capacity values were to be paid in dollars per kW per month and otherwise subject to the requirements of a firm capacity sale.

In examining the utilities' compliance with the OIR 2 decisions, we will first consider the issue relating to all of the above factors, except for termination. A review of the utilities' proposed termination provisions will follow in a separate section.

1. Performance Requirements

A finding of compliance or noncompliance with the requirements of D.82-01-103 enumerated above requires an understanding of each of the utility's standard offer provisions relating to performance. Additionally, the positions of both utilities and interested parties must be considered.

a. PG&E Standard Offer No. 2, Appendix C - Firm Capacity Price Schedule

PG&E's standard offer provisions governing the conditions of firm capacity payments are set forth in Appendix C of its Standard Offer No. 2 (Firm Capacity and Energy Power Purchase Agreement). PG&E's minimum performance requirements are inextricably tied to the type of capacity payment chosen by the QF. These two payment options are described in Section C-5 of appendix C.

Under *Option 1* the monthly payment for capacity, paid in dollars per kW per month, is one-twelfth of the product of the designated per kW annual contract capacity price multiplied by the contract capacity (the amount of energy in kW to be sold and delivered) and by the appropriate loss adjustment factor. In order to receive these 12 equal monthly payments, the QF must meet performance standards which essentially make it dispatchable by PG&E. Specifically, PG&E requires the QF's contract capacity to be available (dispatchable by or delivered to PG&E) during all on-peak hours of the peak months of June, July, and August, subject to a 20% allowance for forced outages in any month. The contract capacity must also be dispatchable throughout the rest of the year subject to a 20% monthly allowance for forced outages and a designated allowance for scheduled maintenance. During these months other than the peak months, the QF may accumulate and apply the 20% forced outage allowance for any consecutive three-month period. Dispatchability is defined by PG&E as the QF being operable and capable of being called upon

at anytime to deliver capacity at any level up to the full contract capacity. The QF must demonstrate that its facility is fueled by a reliable fuel supply and that adequate fuel storage is available to deliver power as requested by PG&E's system dispatcher.

Option 2 provides for payments to QFs, again in dollars per kW per month, for the amount of capacity actually delivered during peak and partial peak hours. A formula for calculating this payment is specified in Option 2 and includes a 20% forced outage allowance credit for each month. Although a QF electing Option 2 must deliver its full contract capacity to PG&E during the peak hours of the peak summer months subject to a 20% forced outage allowance, no other performance requirements are imposed for the rest of the year. During the summer peak months, the 20% forced outage limitation and the measurement of performance according to deliveries means that the QF must deliver the contract capacity at least 80% of the peak hours, thus achieving a peak period capacity factor of 80% during the summer months. During the rest of the year the QF is paid for capacity according to how much energy is delivered, but there is no specified performance level that must be met.

Under Option 1 the QF is dispatchable and has its performance judged according to its *availability* or ability to deliver whereas under Option 2 the QF is not dispatchable and has its performance judged according to its *output* or actual deliveries. Also, under Option 2 performance is only judged during the peak summer months whereas under Option 1 there are certain year-round requirements. Apart from these basic differences the remaining provisions of Appendix C are, for the most part, identical for both options. These provisions include a limitation on contract capacity price used to calculate QF payments under either option of 100% of PG&E's shortage costs.

Additionally, to qualify for firm capacity payments, outages for scheduled maintenance (i) cannot occur within the first six months of operation, (ii) cannot occur between May and October unless otherwise agreed to in writing with PG&E, (iii) cannot be undertaken without six months' prior written notice to PG&E's system dispatcher, and (iv) cannot exceed a total of 35 days in any 12-month period. Both options permit capacity payments to continue during the period allowed for such scheduled maintenance.

Section C-3 of Appendix C governs failures to meet the minimum performance requirements. Essentially, this section applies (i) if an Option 1 QF fails to have at least 80% of its contract capacity available during the peak hours of the peak summer months or the allowable percentage, taking into account properly accumulated allowances for forced outages in other nonpeak months or (ii) if an Option 2 QF fails to deliver at least 80% of its contract capacity during the peak hours of any of the peak months. If the reason for this failure is other than a forced outage or force majeure, PG&E may immediately suspend the payment of capacity charges for a probationary period not to exceed 15 months. If a QF can meet the minimum requirements during the probationary period, PG&E will pay the QF all capacity payments suspended during the probationary period and reinstate regular capacity payments. If a QF cannot meet its minimum requirements during the probationary period, PG&E may derate the contract capacity to either actual or reasonably expected deliveries, with the quantity by which the capacity is reduced being subject to termination provisions. If the failure to meet minimum requirements was caused by a forced outage,[1] the QF will not receive capacity payments for the month in which this circumstance occurred. During a force

[1]PG&E defines forced outage as any outage resulting from a design defect, inadequate construction, operator error, or a breakdown of the mechanical or electric equipment that fully or partially curtails the electrical output of the QF.

majeure, capacity payments will be continued for a period of 90 days following the occurrance.

Finally, PG&E's Appendix C provides no special provisions for any technology other than hydroelectric projects. The only separate provisions for small hydro QFs deal with the determination of the QF's monthly capacity rating. The procedure followed by PG&E mirrors the requirements of D.82-01-103, i.e., with the average dry year being based on the average of the five years of the lowest annual generation as derived from 50-year natural flow data. The small hydro QF is otherwise required to meet the minimum performance requirements for either payment option chosen.

(1) Positions of the Parties

During the hearings and in briefs, both criticism of and support for PG&E's performance requirements were voiced. Generally, IEP, whose views were shared by the State Energy Task Force, found all of the utilities' proposals too rigid and, like the CEC, endorsed statewide performance standards which would be more flexible. IEP asserts that PG&E's offer improperly excludes wind and waste-to-energy facilities by imposing overly strict performance standards during summer peak periods and inflexible scheduled maintenance requirements. Other parties, including CMA, Calcogen, and Kimberly-Clark, however, endorse PG&E's approach which allows performance to be measured by availability as well as energy production. The staff concludes that, with certain modifications, PG&E's Option 1 is a reasonable model for an offer based on availability.

Parties both supporting and disputing PG&E's general approach, however, also had a number of specific recommendations. To begin with, it was urged that payments above 100% of PG&E's shortage costs should be offered to QFs whose performance exceeds the operating standards normally expected of PG&E plants. The staff sug-

gests that payments should be provided up to 125% of PG&E's capacity costs and should be calculated according to a recommended formula for an additional capacity credit. Staff also suggests that PG&E's definition of dispatchability be modified to give the utility the right to require only increases, not decreases, in a QF's operation and to limit dispatchability to on- and mid-peak periods and emergencies.

IEP and other QFs ask that statewide maintenance standards be adopted which would allow (a) hourly use of the alloted time, (b) an additional 45 days or use of accumulated unused days every three years for major overhauls, and (c) notice requirements related to the amount of time to be used (i.e., 24 hours' notice for a maintenance period less than 24 hours, seven days' notice for maintenance in excess of 24 hours, and six months' notice for major overhauls). The special needs of waste-to-energy projects which require 55 days a year for maintenance should be recognized.

IEP and the staff also urge that all capacity payments should not be suspended during PG&E's probationary period. IEP testified during hearing that such an interruption in cash flow could cause a QF to meet its debt service obligations. Both the staff and IEP recommend that during the probationary period the QF be paid for the actual level of capacity performance it can achieve. At the end of the period, payments should be reinstated based on the level of operation which the facility can reliably perform. Staff states that the capacity payments suspended for the capacity actually delivered should include an allowance for forced outages.

Finally, a number of the parties recommend that adjustments be made in PG&E's approach for small hydro and waste-to-energy facilities. Staff concludes that since the contract capacity of a small hydro facility is based on the average of five years low flow during peak months,

such a facility should not be further penalized for failing to meet PG&E's peak availability standard in years when flow is less than the five-dry-year average. Staff recommends that PG&E's performance factor, part of the payment calculation for Option 2 QFs, should be set at 1.0 in establishing the nameplate capacity for small hydro QFs and that the peak availability requirement should be waived. Further, staff urges that termination provisions should not be applied to hydro QFs who fail to deliver the contracted capacity only because of low flow conditions.

For waste-to-energy projects, the staff asks the Commission to consider developing over the next year the proper data and methodology required to base capacity payments to waste-to-energy projects on the combined performance of all such projects during the peak months. The group performance would be compared to a utility's baseload plants and the individual waste-to-energy facility would be paid according to its performance as compared to that of the group.

(2) PG&E's Response

In its brief, PG&E asserts that the provisions of its Appendix C are in full compliance with the OIR 2 decisions. Only to accommodate QF development does PG&E suggest any modification of its approach. In particular, it is PG&E's opinion that no adjustments to its minimum performance requirements are necessary for specific technologies, such as wind or solar, since a QF which cannot meet those requirements is less valuable to the utility than one which can. Further, a QF always has the option of signing an as-available contract which was specifically designed to accommodate resource uncertainty.

With respect to payments above 100% of PG&E's shortage cost for QFs whose performance exceeds utility plant, PG&E argues that such a payment should only be made to QFs that can actually outperform utility combustion turbines and only if they can do so on a consistent basis.

PG&E allows QFs to have a "liberal" 20% peak period forced outage rate under its standard offer but contends that its own peaking units have forced outage rates that are actually less than this amount. Therefore, for QFs to receive payments in excess of the combustion turbine shortage cost proxy, they must outperform this higher standard of the combustion turbine (i.e., a 10% or 15% forced outage rate). Further, they must commit to achieve this performance on a consistent basis.

On the issue of scheduled maintenance, PG&E contends that the standard offer should not become a "lowest common denominator" contract which is stretched to accommodate specific technologies that cannot meet reasonable requirements. For a QF which cannot meet PG&E's requirements, a special agreement or an as-available contract again is always an option. PG&E is willing, however, to allow a QF when it enters the contract either (1) to take only a portion of the allowed number of days per year for scheduled maintenance and combine the remaining days over three years into maintenance periods for major overhauls or (2) arrange an average of 35 days per year over the life of the contract allowing an increasing number of days for maintenance as the project ages.

PG&E is also of the opinion that a probationary period of at least 15 months is necessary to allow PG&E to assess the level of capacity the QF can reliably deliver or make available during the peak months after it has failed to perform. PG&E is willing, however, to redraft its provisions covering the suspension of payments during this period in keeping with the suggestions made by IEP during hearings.

Specifically, PG&E proposed that under Option 1, if a QF fails to meet the minimum performance requirements, it will continue to receive capacity payments for the amount of dispatchable capacity available during the probationary period. If after the expiration of this period, the QF has

not demonstrated an ability to provide its full contract capacity to the utility that capacity would be derated subsequent monthly payments limited to the new contract capacity. The amount by which the QF's capacity is reduced will be subject to termination provisions.

For Option 2 QFs, the same opportunity to earn capacity payments during the probationary period for the amount of capacity actually delivered will be provided. If the QF fails to deliver the full contract capacity during each of the following year's peak months, the contract capacity will be derated to the lower monthly amount of capacity actually delivered during the peak months. The lost capacity will again be subject to termination provisions.

PG&E does not support staff's position regarding adjustments of PG&E's capacity payment formula for small hydro QFs. According to PG&E, a hydro QF already benefits from the increase in its capacity rating caused by basing that rating on the average of five dry years, rather than the driest year. PG&E does believe, however, that hydro QFs during the "drier" year should have their capacity payments suspended, as opposed to having the contract terminated, as follows:

> "1. Hydro QFs which have their capacity ratings based on the five dry year average should not have their capacity terminated or derated when their failure to meet the minimum performance requirements is due solely to the occurrence of a dry year which is drier than the five dry year average.
>
> "2. During 'drier' year conditions, capacity payments to hydro QFs should be suspended. Capacity payments should resume, at the contract price, when hydro conditions once again reach the level used to determine the capacity rating." (PG&E's concurrent brief, at pages 31-32.)

b. Edison Standard Offer No. 2 Part I, § 13 (General Terms and Conditions - Availability) and Appendix B. 2 (Capacity Payments for Firm Power Purchases)

Unlike PG&E, which offers payments for firm capacity based on availability and energy production, Edison's standard offer provides only one basis of payment for a firm power purchase - the QF's energy production. Basically, under Edison's firm capacity offer, the QF is paid according to its output or capacity factor. In addition, its emergency availability is considered.

The QF's output or capacity factor is taken into account in two ways in the payment provisions included in Appendix B. 2 of Edison' Standard Offer. First, the QF is paid more for achieving a higher capacity factor or a level of kWh output that is a higher percentage of the maximum possible kWh output given the kW contract capacity. At an 80% capacity factor the QF is paid 100% of the per kW capacity price for each kW of contract capacity. At higher capacity factor levels, representing performance in excess of Edison's plants, the price paid per kW is escalated further, up to a maximum of 124% of the basic per kW capacity price for 100% capacity factor performance.

The second way in which output is taken into account is through Edison's "hurdle factor". If a QF output falls below a 50% capacity factor (the "hurdle"), its capacity payment is cut in half for that period. Edison claims that this hurdle factor takes into account QF reliability because QFs that do not perform within a certain range (greater than the hurdle) are less reliable and less valuable.

The "hurdle factor" is the only aspect of Edison's offer that indirectly requires a prespecified level of output. As noted earlier, under PG&E's output-based option, QFs must meet an 80% summer peak output requirement or face probation and termination of all or part of their contract

capacity. Here, QFs must meet a 50% output level in any month (not just peak summer months) or their payments are reduced. Under the Edison scheme, termination penalties would not apply.

Edison's offer also has an emergency availability requirement. Emergency availability is defined in Section 13.2 as follows:

> "At Edison's request seller shall, within 30 minutes of such request, make all reasonable effort to deliver power at an average rate of delivery at least equal to the (contract) capacity . . . during periods of emergency."

If the QF Seller fails to respond, its capacity payments are reduced by one-half for the six months following the request "until Seller demonstrates (the) ability to deliver full capacity pursuant to Section 13, Part I, or until Seller responds to a subsequent request for full capacity, in which case the six-month capacity payment reduction shall be waived for the remaining reduced payment monthly billing periods." In all cases, however, the reduced payment will apply to the month in which the Seller fails to respond to a capacity request.

In addition to these requirements contained in Appendix B. 2, Section 13 also provides that a QF which fails to respond to an emergency when first requested by Edison will not have its capacity payments reduced. However, after this initial request, whether complied with or not, any subsequent failure by the QF to comply with a request by Edison will result in the aforementioned 50% reduction of capacity payments specified in Appendix B. 2. Failure to comply with a request during an existing six-month reduced capacity payment period will extend that period to six months following the latest failure.

Edison contends that its "availability factor" provides a specific way of valuing QF emergency availability, one

of the factors that required by D.82-01-103 to be reflected in the firm capacity payment. The availability criterion is somewhat analogous to the availability required under PG&E's dispatchability option (Option 1) except that there is no allowance for forced outages as in the PG&E's example, and under the Edison's offer the requirement is a part of an output or capacity factor-based payment scheme.

Edison's payment formula also reflects adjustments for scheduled maintenance. Specifically, Edison allows a maximum of 480 hours (20 days) per year for scheduled maintenance and an additional 1,080 consecutive hours (45 days) once every three years for major overhauls. In Part I, Section 8.4, of its offer, Edison defines reasonable advance notice of scheduled outages, including any reduction in capacity availability as 24 hours for an outage of less than one day, one week for an outage of one day or more, and six months for major overhauls. The off-peak hours are to be used for scheduled and routine maintenance and the QF is required to make reasonable efforts to limit its outages during on-peak and mid-peak periods.

(1) Positions of the Parties

Many of the parties found the same general shortcomings in Edison's offer as PG&E's. For example, QFs complain that here, as in the case of PG&E, many performance requirements are rigid, "all or nothing" type requirements that do not adequately reward partial performance.

In addition, a number of specific criticisms of Edison's offer were raised. In particular, several QFs complain that Edison has failed to make an offer based on availability similar to PG&E's. Staff agrees that Edison should have an availability option. In staff's view, a forced outage rate is the proper performance criterion under such an option. Staff also contends that this availability option should reflect, as Edison's current "output" offer does, a higher payment for operation better than Edison's plants.

QFs note that whereas PG&E's performance requirements would appear to exclude technologies that cannot be dispatchable (Option 1) or meet an 80% summer peak output requirement (Option 2), Edison's offer would not exclude any technologies. In other words, under Edison's offer, there would be no lower limit or absolute eligibility for the firm capacity contract, as even QFs that cannot meet the availability and hurdle factors would receive some capacity payment, however small. Still, many parties object to the hurdle and availability factors as being too rigid and harsh. The deletion or adjustment of these factors is recommended, particularly for certain technologies.

Staff observes that Edison's own plants would have difficulty meeting a 30-minute response time required by Edison for QF emergency availability. Instead, staff argues that Edison should only require that a QF make reasonable efforts to respond to an emergency as soon as feasible consistent with its capabilities. CMA also agrees that technical feasibility is the proper criterion for meeting any emergency and argues that lack of emergency availability should not have such a major impact on capacity payments since it represents only a small fraction of a utility's total avoided costs. IEP suggests that the availability factor should not be applied to a QF on full or partial forced outage which has notified Edison in advance.

IEP recommends that a sliding scale be used in applying the hurdle factor rather than a single 50% capacity factor cutoff. IEP contends that this sliding scale will better reflect the actual level of capacity the QF is contributing to the system. The State Energy Task Force voices the concern that neither the hurdle factor nor the availability factor is applied to Edison's own plants and that these factors require QFs to meet a stricter performance test than utility plants.

If the availability and hurdle factors are to be adopted as proposed by Edison, several of the parties urge that

the availability factor be waived for solar (both solar-thermal and solar-photovoltaic) and wind technologies, with wind's nameplate capacity being derated by 20%. For reasons similar to its suggested modifications of PG&E's offer for small hydro, staff recommends that Edison's period capacity, hurdle, and availability factors be set at 1.0 for hydro QF's whose capacity rating is based on the average of the five lowest flow years. For waste-to-energy projects, IEP and the California Waste Management Board ask that these QFs be given a longer time to respond to an emergency consistent with the technology (eight hours) and that the calculation of their capacity payment not include the hurdle factor.

Most parties endorsed Edison's basic approach to the allowed time and notice for scheduled maintenance. IEP, for instance, recommends Edison's offer as a model for statewide scheduled maintenance standards. IEP would only modify Edison's language by increasing the yearly allowance for scheduled maintenance to 35 days. For waste-to-energy projects, the California Solid Waste Waste Management Board again recommends a yearly allowance of 55 days.

(2) Edison's Response

Like PG&E, Edison believes that its performance criteria for firm capacity payments fully comply with the OIR 2 decisions. In particular, Edison asserts that both its availability and hurdle factors are reasonable. Edison argues that QFs that cannot consistently achieve a capacity factor above its 50% "hurdle" are less reliable and less valuable and they should, therefore, have their capacity payment reduced as Edison does in its standard offer. Similarly, Edison believes that a QF which is not available during emergencies is less valuable and that this situation also warrants reduced capacity payments.

Edison argues that the emergency availability requirements is appropriate even if Edison does not impose a

similar requirement on its own plants and its plants and the QF plant are treated differently. Edison contends that it is appropriate to treat the two differently since they have different obligations. The utility, by virtue of its retail franchise, has an obligation to serve customers at all times whereas the QF has no incentive beyond price to serve Edison's ratepayers during emergencies. Edison contends that the 30-minute response time that it requires for QF emergency availability is reasonable and that any adjustments should only be considered on a case-by-case basis.

Edison does offer to modify the application of its hurdle and availability factors for specific technologies. In particular, Edison has adopted the adjustments suggested by the staff for wind, solar, and hydro with the exception of retaining the period capacity factor for small hydro to permit the capacity payment to be based on actual performance.

Edison also states that it is willing to pay QFs in dollars per kW per month based on availability, but only if the QF is fully dispatchable and is as reliable as Edison's generating resources. According to Edison this dispatchability and reliability will require (1) an accurate measurement of QF availability during each time period for each season; (2) detailed, accurate, and verifiable QFs records with periodic company review to determine a QF's actual energy production; (3) a QF being the functional equivalent of an Edison combustion turbine or the purchased power used by Edison to develop its shortage costs; (4) a QF's performance being measured individually and not in the aggregate; and (5) full dispatchability permitting the utility to increase and decrease generation. As in the case of PG&E, staff disagrees with this view of dispatchability and recommends that Edison should not have sole discretion over a QF's operation and should be allowed only to require increases in a QF's production or availability.

In recognition of the wide variation of QF's scheduled maintenance requirements, Edison endorses modification of its standard offer to allow more flexibility in scheduled maintenance allowances. Specifically, Edison will provide 35 days of scheduled maintenance per year and a year-to-year accrual of unused maintenance days, not to exceed 45 days.

c. SDG&E Standard Offer for Firm Capacity, Section 6 (Purchase Price of Energy and Capacity) and Exhibit C (Capacity Payment Schedule for Firm Capacity QFs)

SDG&E offers two payment options to QFs signing its firm capacity contract. Both options, set forth in Exhibit C of the offer, are based on energy production, as opposed to availability, and the choice of capacity payment option is limited by the payment option selected for the QF's sale of energy to SDG&E. If a QF elects energy Option 1 (as-available energy), it will be paid for capacity only according to capacity Option 1. A QF choosing energy Option 2 (five-year forecast) can be paid for capacity under either capacity Options 1 or 2. The two options for capacity payments are based on two different performance criteria which must be met for payment.

Under Option 1, capacity payments are made on the basis of the QF's output or energy actually delivered. A QF starts with a certain levelized annual capacity price in dollars per kW which varies depending on the length of the contract that the QF signs and the year its operations start. This annual price is spread to different hours within the year based on a "supply factor", an allocation factor that values capacity more during seasonal or daily peak demand hours. The resulting ¢/kWh capacity prices for different time periods are paid to the QF for all the kWh energy output that it provides in each time period. There are no prespecified output or availability performance levels that must be met. There are no conditions to or limitations on scheduled maintenance.

Option 2 is entitled Payment by Capacity ($/KW-month). Under this option, payment is based on output or capacity factor and requires that certain peak period performance standards be met. The Option 2 monthly capacity payment equals the product of the Equivalent Capacity Factor (ECF) and the appropriate $/kW number in the capacity table again determined by the length of the contract and the QF's operation date. The ECF is calculated as follows:

$$ECF = \frac{QxA}{Cx(H-S)xR}$$

Under this formula, Q represents the delivered energy in kWh during monthly on-peak and semi-peak time periods; A is a monthly capacity allocation factor differentiated by season; C is the contract capacity; H stands for the total monthly on-peak and semi-peak hours; S is a QF's monthly scheduled maintenance during on-peak and semi-peak hours, which is not to exceed 75% of H; and R is the reliability of SDG&E's system alternative capacity source. R currently has a value of 0.85.[2]

To be paid under this formula, a QF must (a) deliver enough output during peak and semi-peak hours of the month so that the monthly ECF is greater than 0.5 and (b) schedule outages at least six months in advance during periods acceptable to SDG&E. Scheduled outages must not exceed 720 hours (30 days) in any 12-month period. Agreed dates for scheduled maintenance cannot be changed without notice.

If the QF fails to meet the minimum performance provisions set forth in Exhibit C, SDG&E will immediately suspend or reduce the capacity payments to the QF for a probationary period. The terms and conditions of this suspension, set forth in Section 16.5 of the standard offer, are similar to those in PG&E's standard offer, except that

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[2]SDG&E bases this 85% reliability on its own peaking plants, which is asserts have, at most, a 15% outage rate.

the probationary period is not to exceed 14, as opposed to 15, months.

(1) Positions of the Parties

Unlike their response to the offers of the other utilities, a number of QFs, generally represented by IEP, endorse SDG&E's approach and urge its adoption for both PG&E and Edison.[3] IEP believes that SDG&E's two-option contract will appeal to a wide variety of QFs. In IEP's opinion, SDG&E's Option 1 correctly recognizes the valuable contribution which a QF can make to the utility system just by signing a long-term commitment. Although a QF could achieve a higher payment agreeing to the more stringent requirements of Option 2, a QF who agrees to Option 1 will receive a payment 15% below that of an Option 2 simply by making a long-term commitment.[4]

Other parties however, did find deficiencies in SDG&E's offer. Among other things several parties pointed out that SDG&E does not have an option (such as PG&E's) which values QF's performance based on availability rather than energy production. Further, it was claimed that SDG&E does not allow payment above the 100% shortage cost level for QFs that exceed the performance of utility plant. Staff contends that under Option 1 ¢/kWh payments, a QF that achieves a 100% capacity factor, a performance level better than utility plants, will only receive 100% of the combustion turbine capital cost proxy, not some higher level. Staff would have the Option 1 QF receive 100% of the shortage cost proxy for 80% capacity factor output and 125% for 100% output. Similarly, under Option 2, staff

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[3]IEP specifically suggests that PG&E's and Edison's offers would be acceptable if an option like SDG&E's Option 1 were also part of these offers.

[4]QFs under Option 1 receive 100% of the $/kW annual capacity price for a 100% capacity factor during the year, while QFs under Option 2, by virtue of the "R" in the formula listed above, receive 100% of the $/kW annual capacity price for an 85% capacity factor performance.

would have the QF receive 100% of the capacity price for an 80% capacity factor, rather than 85% as now specified by the reliability factor, R. Use of the 80% standard by staff is based on their estimate of the average reliability of SDG&E's plants or its system as a whole.

None of the parties suggested any adjustments to SDG&E's payment option or performance requirements for specific technologies. Comments regarding PG&E's suspension of payment provisions and scheduled maintenance allowance were equally applicable to SDG&E.

(2) SDG&E's Response

SDG&E is willing to modify its firm capacity offer so that the choice of capacity option will not be limited by the type of energy payment chosen. However, SDG&E concludes that both its Options 1 and 2 are reasonable and consistent with OIR 2. According to SDG&E, Option 1 reflects an aggregate value of firm capacity and is intended for QFs which are unable or do not desire to guarantee a minimum degree of availability. Under these circumstances, Option 1 will be a useful tool in making the standard offers widely applicable to QFs. SDG&E acknowledges, however, that the factors recited in D.82-01-103 for inclusion in a payment for firm capacity are actually contained in its capacity payment Option 2.

With respect to Option 2, SDG&E does not believe it is necessary to have an availability option under which the QF is dispatchable. SDG&E concludes that it would be impossible to measure availability when it is not based on actual output, but is based on a measure of forced outages and the potential to produce output. Further, SDG&E argues that its Option 2 actually reflects availability since it requires QFs to produce a certain amount during peak and semi peak hours. SDG&E's minimum ECF of 0.5 under Option 2 is a standard of peak period reliability and availability.

SDG&E disagrees with staff's contention about payments above 100% of the shortage cost. For Option 1 type QFs, SDG&E argues that they are less reliable and therefore should only receive a maximum of 100% of the shortage cost for 100% capacity factor output (similar to the as-available capacity payment). For Option 2 QFs, SDG&E argues that payments above 100% *are* allowed for capacity factor performance above 85%. This 85% standard is based on a conservative assumption of its combustion turbine plants' reliability. SDG&E disagrees with staff's use of an 80% standard as it incorrectly is based on system reliability rather than peak or plant reliability. Use of the latter standard is appropriate in order to be consistent with the shortage cost proxy approach.

SDG&E offers no changes to its provisions governing suspension of payments or scheduled maintenance. SDG&E observes that its scheduled maintenance allowance is already sufficiently flexible, particularly since restrictions on maintenance only apply during peak and semi-peak periods.

d. Discussion

In D.82-10-103 the utilities were directed to draft a firm capacity contract, designed for QFs that could meet certain operating standards, and an as-available capacity contract, designed for QFs that could not, or did not desire to, meet such standards. The operating or performance standard envisioned in D.82-01-103 for firm capacity QFs was to be a standard which required QF availability during system peak periods. The standard was to designed to reflect aspects of peak period availability such as dispatchability, reliability, availability during emergencies, scheduling of outages, and contract duration, termination, and sanctions. QFs that signed contracts as firm power sources were to meet this specified standard of performance.

We have before us three general types of performance standards in the utilities' filings. The first is a performance standard based on a level of peak period availability, as

exhibited by PG&E's Option 1. The second is a performance standard based on a level of peak period *output,* as exhibited by PG&E's Option 2, SDG&E's Option 2, and Edison's single payment offer. The third is a performance standard that requires only a commitment to a certain contract length with no specific peak period output or availability. This approach is embodied in SDG&E's Option 1.

We find that PG&E's Option 1 availability standard, with the modifications discussed below, is in compliance with the requirements of D.82-01-103. Indeed, as the requirements of D.82-01-103 are oriented towards QF peak period availability, this availability type of standard most clearly follows from this decision. Under this option the QF is dispatchable and available for emergencies. Moreover, because of the limitations on peak periods forced outages, peak period reliability is assured. Nonperformance is deterred by the application of termination provisions. Requirements are made for scheduled maintenance.

All three utilities have proposed a performance standard that is based on a QF achieving a certain level of peak period output. D.82-01-103 specifically allows for a performance option based on capacity factor or output rather than availability. Output requirements are an indirect way to assure availability for nondispatchable units.

We consider PG&E's Option 2 with the modifications discussed below, to be in compliance with D.82-01-103. Under this option the QF must deliver its contract capacity to PG&E at least 80% of the time during the peak hours of the peak summer months. During other periods there are no specified performance requirements, other than scheduled maintenance limitations.

Turning to the aspects of peak period availability recited in D.82-01-103, it is clear that the peak period output requirement in PG&E's Option 2 assures reliable operation during the hours of the year when reliability is most im-

portant. The QF under Option 2 is not dispatchable, but the peak period output requirement and the general weighing of capacity prices toward peak and semi-peak hours assures that QFs will operate during most, if not all, of the same periods as they would have had they been under the dispatcher's control. D.82-01-103 specifically allows for nondispatchable QFs to be accommodated in the firm standard offer. Time-of-use pricing and peak period output requirements under Option 2 will also assure that QFs will be delivering their capacity during the most likely emergency periods. Finally, maintenance scheduling and termination provisions apply as they do in the case of PG&E's Option 1.

The essential requirement of performance under both PG&E's Option 1 and 2 is the 80% summer peak hour availability or output requirement. IEP has argued that this standard is too stringent and one that many utility plants could not meet. We consider the standard to be reasonable for QFs that sign up as firm sources and receive capacity payments based on the combustion turbine. Evidence in this proceeding, with which IEP concurred, indicated that utility peaking plants, such as combustion turbines, have an average peak period availability of greater than 80%.

We do agree with IEP that PG&E's options are too stringent in other ways, such as its requirements for scheduled maintenance. As discussed below, we will require certain changes with respect to this and other performance requirements.

IEP also argues that an 80% peak availability or output requirement is too flexible and is of an "all or nothing" nature. We disagree. Under the reduction in payment provisions which PG&E proposed in its brief, discussed below, a QF that does not achieve the 80% availability or output standard will still receive a payment commensurate with its actual production and will have the opportunity to have

its original capacity payments reinstated if its availability or output reaches the 80% level during the probationary period.

The flexibility of the standard is also enhanced because it may, if need be, only apply to part of the QF's total capacity. In other words, if a 10 MW QF facility produces consistently at a 5 MW level and sporadically at higher levels, the QF can sign up for 5 MW of firm capacity (which meets the 80% standard) and sell the rest of its output on an as-available basis.

SDG&E's Option 2 is like PG&E's Option 2, based on the QF's output. In certain cases, however, this option imposes a more lenient performance standard than PG&E's by requiring only a 50% output level which the QF may fail to meet and still not be exposed to termination or probation provisions. On the other hand, the 50% standard applies to peak and semi-peak hours during all months of the year, not just summer month peak hours. Partial capacity payments are also not allowed for performance that is somewhat below the standard. If the 50% level is not met, the QF receives no payment for that month.

We do not find SDG&E's Option 2 to be in compliance with D.82-01-103. The 50% standard is, in our view, not an adequate level of peak availability and reliability, even if it does apply to more hours of the year. The firm capacity performance standard should be oriented toward the system peak hours when reliability is of greatest concern. It should be a level of reliability that is commensurate with the utility plant that is avoided by QF purchases. Utility plant has a higher level of peak period availability than 50%. Also, it is more reasonable, in our view, to allow more flexibility than SDG&E allows by giving partial payment, rather than zero payment, for performance below the standard. Further, SDG&E's zero payment for nonperformance does not differentiate between temporary and repeated nonperformance. More flexibility should be al-

lowed for temporary nonperformance with termination provisions applied only to continued performance.

We also find that Edison's output-based performance standard is not in compliance with D.82-01-103. Edison's basic performance standard is a 50% output level, incorporated in its "hurdle" factor. In Edison's offer this standard applies to all periods - peak, mid-peak, and off-peak - in all months of the year. Failure to meet this standard results in a 50% reduction in the capacity payment. Edison also requires emergency availability. Failure to meet this standard results in an additional 50% reduction in the payment.

Edison's performance standards do not adequately focus on peak period availability as required by D.82-01-103. Apart from the emergency availability requirement, there is little differentiation between required peak and off-peak performance. The 50% output level is also too lenient for the peak period. On the other hand, the emergency availability requirement is too stringent and places too much emphasis on one aspect of peak period availability. It is for these reasons that we find that Edison's performance requirements for firm capacity QFs do not comply with D.82-01-103.

The final type of performance standard that we must consider is SDG&E's Option 1. This option appears to be a hybrid of the standard offers approved in OIR 2, an offer which could lead essentially to a long-term as-available capacity contract. Although a QF electing SDG&E's Option 1 would be committing its resource for a specified period of time at a price which would vary by time of energy delivery, the QF would not be required either to be available during peak periods and emergencies or to match the reliability of SDG&E's own plants. We understand the reasons many QFs have found such an option desirable, i.e., the opportunity to have payments which would be levelized and possibly greater than those paid

an as-available producer. Nevertheless, Option 1, failing to reflect the required performance standards, is not an option to purchase firm capacity as defined in D.82-01-103. While we might consider such a hybrid in the future, it was neither contemplated by nor in compliance with that decision.

Because of our conclusions, it will be necessary for the utilities to refile their standard offers in conformance with this order. Although we believe that PG&E's Options 1 and 2 can serve as appropriate models for firm capacity standard offers based on availability and energy production, even these offers require modification. Neither SDG&E nor Edison will have complied with the OIR 2 decisions until each offers payment options based on a QF's availability and energy production equivalent to those offered by PG&E, as modified herein.

To achieve overall compliance with this decision and OIR 2, the following principles should be incorporated in the utilities' firm capacity standard offers.

(1) Dispatchability

We concur with the staff that the definition of dispatchability used in PG&E's Option 1 and any other offer based on availability should give the utility the right to require only increases, not decreases, in a QF's operation. At this time the language employed by PG&E (required capacity deliveries "at any level up to the full contract capacity") is ambiguous, but appears to permit both upward and downward dispatchability. We agree with the staff that the ability of a utility to interfere with a QF's operations in such a manner is unwarranted and unreasonable. The utility should not be in a position to unilaterally jeopardize a QF's operation and in turn reduce its payments. Regarding dispatchability, D.82-01-103 only required that a QF be sufficiently dispatchable to be available for a utility's *increased* needs during peak periods and emergencies. For

these reasons, we also find Edison's approach to dispatchability too restrictive.

We do not believe it is necessary, however, to define dispatchability as limited to on- and mid-peak periods and emergencies if an approach like PG&E's is used. Such a limitation is both implicit and explicit in PG&E's Option 1. For the peak months, a QF signing Option 1 is required to have 80% of its capacity available only during the peak hours and for the remainder of the year need only maintain a somewhat flexible forced outage rate. Because PG&E offers no method for checking on a QF's ability to respond in every hour of each day, but rather uses an on-call approach, a QF will at least have the minimum ability to respond consistently to system emergencies which cannot be predicted.

While we could adopt Edison's response time (30 minutes) criterion for emergencies, we believe that the record in this proceeding is not sufficient to designate a specific response time for all utilities and that PG&E's requirements essentially accomplish this same result by ensuring a QF's readiness to perform. The only time PG&E would possibly need to increase a QF's supply is at times when its own demand increases (i.e., peak, semi-peak, and emergencies). PG&E's approach allows a QF to meet all of these performance factors without placing an unreasonable burden on a QF's operation or one inconsistent with PG&E's plant operations.

(2) Payments in Excess of a Utility's Capacity Costs

We conclude that an option is not in compliance with D.82-01-103 or this order unless it provides for payments in excess of a utility's capacity costs to QFs whose performance exceeds that of the utility's plants. We do not believe that a firm capacity QF must be the exact functional equivalent of a utility's peaking combustion turbine to receive an offer based on 100% of a utility's capacity costs. However, we do agree with PG&E that to receive

higher payments the QF's consistent level of performance should exceed the minimum level of availability of the peaking unit used as a proxy to calculate the utility's shortage costs. Such a requirement will ensure that the utility will not pay more than its avoided costs, the previously determined level of payment found reasonable for QF purchases.

Testimony during hearing indicated that the availability factor of a combustion turbine could range from 80% to 94%. To receive higher payments, a QF should at least meet a comparable level of performance during the utility's peak periods. We believe that it is reasonable, therefore, to require that a QF achieve a peak period availability or capacity factor in excess of 85% before receiving capacity payments in excess of 100% of the shortage cost proxy. Thus, a utility's payment options should include an offer to pay a price higher than the utility's stated capacity costs for those QFs (1) who demonstrate an availability of 85% or better during time periods similar to those specified in PG&E's Option 1 or (2) who deliver capacity during the peak periods at a capacity factor of 85% or better under an output option like PG&E's Option 2. Under these circumstances, a QF who performs at this higher level could receive up to 118% of a utility's shortage cost.

We believe, however, that an additional requirement should be imposed in an availability option which permits the higher payment. PG&E currently intends under its Option 1 to measure a QF's dispatchability by placing the QF "on-call". We believe that a more certain measure of the QF's dispatchability should be required if a QF is to receive payments above a utility's avoided costs in order to ensure whether and at what level the QF actually exceeds utility plant operations. Such a demonstration is therefore required not only to justify the higher payment, but to determine the appropriate level of that payment.

For this reason, we will direct the utilities to include in their standard offers a reasonable method of determining the QF's consistent ability to be available at a forced outage rate of 15% or less. Although SDG&E argues that more operating experience is required to determine a QF's forced outage rate, it is our view that having set the standard (performance at an availability factor of 85% or better) the utility can devise methods to review the QF's actual performance. It is *only* in this case of higher payments that Edison's reporting requirements which it felt were necessary for a QF to be dispatchable might be appropriate.

(3) Adjustments for Specific Technologies

Edison proposed certain adjustments in its firm capacity performance standards for solar and wind technologies. Basically, Edison is willing to waive its emergency availability standards for both technologies and waive the 50% "hurdle" or output standard for wind. Under these circumstances, the capacity payment for wind would be reduced by 20% while the solar payment would be unaltered. As we have not found Edison's performance standard to be in compliance with D.82-01-103, these modifications are essentially no longer at issue. As discussed earlier, we believe that the performance standard that we have adopted, modeled after that proposed by PG&E, offers sufficient flexibility for QFs that can meet a specified level of performance. QFs which cannot meet the specified level of performance can sign an as-available capacity contract or enter into negotiations for a nonstandard contract.

D.82-01-103 did provide a special capacity price adjustment, however, for small hydro facilities. We do find that some clarification of this adjustment is required.

Basically, we have concluded that the position taken by PG&E in response to this issue, recited *supra*, is reasonable with one exception. In its brief PG&E has suggested altering its contract provisions governing the suspension

of payments for failure to meet its minimum performance requirements. Instead of suspending all payments, PG&E will modify its offer to specifically permit payment for the capacity actually delivered during the probationary period. Because we intend to adopt this approach, we believe it is consistent to permit hydro QFs operating during the "drier" year to be paid for the amount of capacity, if any, actually delivered to the utility during this "drier" year period. Capacity payments would resume at the contract price, with no retroactive payments, when hydro conditions once again reach the level used to determine the capacity rating. With this modification PG&E's recommendation should be included in every utility's firm capacity standard offer for hydro QFs whose payments are based on the five dry year average.

(4) Scheduled Maintenance

As in the case of availability requirements, we believe that scheduled maintenance requirements in the firm capacity offer should be reasonably consistent between utilities. We agree with PG&E that our standards for firm capacity should not be formulated based on the "lowest common denominator" and should not jeopardize avoided cost value. However, we also conclude that scheduled maintenance standards should be sufficiently flexible to permit various types of QF operation. Essential elements of any scheduled maintenance allowance should be (1) a reasonable allotment of days for both routine maintenance and major overhauls, (2) sufficient notice to aid utility system planning, and (3) appropriate timing to avoid periods of greatest demand on the utility system.

We believe that these basic principles are embodied in Edison's approach to scheduled maintenance with certain modifications. Therefore, an offer which complies with this decision and OIR 2 must allow the following:

a. Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-

month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis.

b. A QF may accumulate unused maintenance hours on a year-to-year basis up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls.

c. Reasonable advance notice to the utility of a scheduled outage will be 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for a major overhaul), and six months for a major overhaul.

d. Major overhauls shall not be scheduled during the peak summer months. Reasonable efforts to schedule or reschedule routine maintenance outside the peak summer months should also be made, but in no event shall outages for scheduled maintenance exceed 30 peak hours during the summer peak months.

e. No restrictions should be imposed on the use of the scheduled maintenance allowance during the initial period of operation (i.e., the first six months).

(5) Reduction of Monthly Payments

For payment options based on either availability or energy production, we generally adopt PG&E's altered approach for reducing payments following a failure to meet the utility's minimum performance requirements. PG&E's original proposal provided that such a failure would result in a total suspension of capacity payments for up to 15 months. Its modified approach, however, would permit payments for capacity actually delivered during the probationary period with the potential of the original payment

level being reinstated or the QF's capacity derated at the end of that time depending on the QF's performance during the peak months. If the QF is unable to deliver its promised firm capacity, the utility should have the ability, as suggested by PG&E, to make that determination over a reasonable period of time. Given the peak month periods of all three utilities, a probationary period of 15 months is reasonable.

Within that time, however, the QF should not experience a total cessation of cash flow if it has a capacity contribution to make to the utility's system. The complete suspension of monthly payments when this circumstance exists is an unreasonably harsh penalty to impose on a Qf whose failure to perform may have resulted from its level of operation during a single peak month. To permit the QF to continue to be paid for capacity actually delivered during the probationary period is a necessary and reasonable part of a more flexible performance requirement.

We agree with PG&E that the QF's ability to meet the minimum performance requirements in peak months following its failure should be used to determine whether its original capacity payment will be reinstated or its contract capacity derated. The difference between the contract capacity and the reduced capacity is appropriately subject to contract termination provisions. We also adopt staff's recommendation that for the capacity actually delivered during the probationary period an allowance or credit for forced outages at the level otherwise specified in the agreement should be included. In using this approach, no retroactive payment at the end of probation is necessary.

(6) As Available Capacity Payments Prior to Firm Capacity Delivery

During hearing one additional recommendation was made by IEP witness Philip M. Huyck, which although not strictly a compliance issue, does relate to the performance required under a firm capacity contract. It was Huyck's

suggestion that a QF under a firm capacity contract who produce energy during start-up periods before the facility is ready to begin delivery of firm capacity should receive an as-available capacity payment up to the time that its firm capacity operations commence.

Although PG&E and Edison agree in general principle with this proposal, staff asserts that the theoretical basis which supports a payment for as-available capacity does not exist for such a payment during a start-up period. Because of the generally short period involved for start-up and the fact that a utility would probably not have a large number of generating plants in start-up at the same time, there can be no aggregation of energy, as in the case of as-available capacity, to serve as the basis for the utility avoiding capacity costs. Staff suggests that under these circumstances only as-available *energy* payments should be allowed.

After reviewing IEP's recommendation, we find SDG&E's response to this issue to be the most appropriate. Specifically, SDG&E states at page 21 of its concurrent brief:

> "...If a QF has declared an Operation Date, which is defined to be the date the plant is deemed to be capable of reliable delivery of energy and capacity..., the QF will be expected to provide capacity from that date. If the QF is unprepared to deliver capacity at the Operation Date, a different date should be chosen. If the QF anticipates there will be start-up problems, but believes it is entitled to receive some capacity payments, SDG&E suggests that the QF execute an as-available contract of short duration to cover the period in which the QF anticipates start-up difficulties. When the QF is confident that it can provide firm capacity, [it] can commence performance under a firm capacity contract."

By adopting this approach, no additional provisions will be required in the firm capacity contract which might be in conflict with the basis of that offer or, as pointed out by the staff, the theory of an as-available capacity offer. SDG&E's suggestion illustrates the existing options available to a QF under the offers we have already approved.

2. Termination Provisions

While D.82-01-103 included contract termination as a factor to be reflected in firm capacity offers and payments, the decision set forth no specific guidelines governing such provisions. The utilities have properly responded to OIR 2 by including termination provisions in each of their firm capacity standard offers. Within these provisions are liquidated damage clauses intended to reimburse the utility for unearned capacity payments made to QFs and, in some cases, the utility's costs of replacing the lost capacity. Certain of the offers place a value on, and in turn propose a reduction in the damage amount for, advance notice of termination.

In addition to issues related to the damage clauses of the utilities' standard offers, some of the QFs questioned the application of termination provisions to a conversion from a simultaneous purchase and sale of energy to a sale of surplus only. The proposals of the utilities and the views of the other parties on each issue are summarized below followed by our resolution of the issue.

a. Damage Clauses

(1) PG&E - Standard Offer No. 2, Appendix D

PG&E's standard offer for firm capacity distinguishes between two types of termination: termination with prescribed notice (Appendix D, Section D-2) and termination without prescribed notice (Appendix D, Section D-3). The length of the prescribed notice is directly related to the amount of the contract capacity being terminated or re-

duced. This notice ranges from three months for 1,000 kW or less to 60 months for over 100,000 kW.

In the event the prescribed notice is given, the QF terminating its contract is only required to refund to PG&E an amount equal to the difference between the capacity payments already paid by PG&E and the total capacity payments which PG&E would have paid based on the period of the QF's actual performance. This approach is adopted to effect a repayment of overpayments in the early contract years that arise from levelization of the capacity price. Interest is to be paid on the refund at the prime rate as published by the Bank of America. For the amount of capacity terminated, the QF will receive, from the date of notice to the date of actual termination, capacity payments based on the capacity price adjusted to the period of the QF's actual performance.

For termination without prescribed notice, a QF is required to make the refund described above, as well as the following additional payment:

> "Seller shall pay PGandE a one-time payment equal to the amount of contract capacity being terminated times the difference between the current capacity price on the date of termination for a term equal to the balance of the term of agreement and the contract capacity price, pro-rated for the length of notice given, if any, by multiplying by one minus the ratio of the actual number (as set forth in paragraph D-2). In the event that the current firm capacity price is less than the contract capacity price, no payment under this paragraph D-3 shall be due either Party." (Section D-3.)

In support of its termination provisions, PG&E points out that the levelized capacity payments made under a firm capacity contract provide a steady revenue stream to the QF with a greater portion of the contract income being

received in the early years. Without full contract performance, overpayments should be recaptured to ensure that the QF is only paid based on the costs the utility actually avoided from the QF's operation. In PG&E's view, interest on this refund is reasonable in recognition of the time value of money.

PG&E also believes that its method of calculating damages for termination without adequate notice is consistent with the principles of contract law. Specifically, PG&E contends that it has used an established measure of damages: the difference between the contract price and the replacement cost. According to PG&E, the presence of this provision also serves to encourage QFs to give adequate notice of termination, while limiting the damages caused by a QF to one year's worth of the replacement cost differential.

(2) Edison - Standard Offer No. 2, Part I, Section 5

Under Edison's standard offer, a QF terminating the agreement is required to reimburse Edison for unearned capacity payments according to the following formula: (1-X/N) times the total value of capacity payments paid to date of termination, where "X" is the number of completed years of service from the initial firm capacity delivery date and "N" is the firm contract length. No specific formula is designated for damages associated with Edison's replacement costs. Edison also requires a QF to provide evidence, "to Edison's satisfaction," of its ability to make potential termination payments.

Edison defends its approach, which places no value on advance notice, as requiring the contracting parties to live up to their obligations unless uncontrollable forces intervene. Edison is critical of contract provisions permitting a QF to "buy out" the remaining term of its contract, i.e., PG&E's proposal, since such provisions will encourage QFs to ignore their obligations. According to Edison,

whenever a QF terminates, even with notice, the utility and its ratepayers are damaged at least to some extent by the utility having delayed or eliminated construction because of a QF's availability.

(3) SDG&E - Firm Capacity Standard Offer, Section 16

SDG&E's firm capacity standard offer includes termination provisions similar to PG&E's contract. A distinction is made between a QF terminating with prescribed notice, for which the basis for reimbursement is specified (Termination Payment A, Section 16.2) and termination without prescribed notice, for which an additional one-time payment is required (Termination Payment B, Section 16.4). The major differences between the two utilities are SDG&E's notice periods (ranging from 12 months for 5,000 kW to 60 months for 20,000 kW or more), its adopted interest rate (simple interest of 12% per year), and its calculation of replacement damages. With respect to the latter difference, Termination Payment B is the sum of Termination Payment A and a one-time payment calculated by taking an adjusted capacity price, based on the QF's actual performance, and inflating that figure by 1% per month for the period of the QF's performance. This figure minus the original firm capacity price is then multiplied by the number of kWs terminated by the QF.

SDG&E supports its approach on grounds similar to those urged by PG&E. SDG&E also points out that adequate notice has a value since it permits the utility sufficient time to purchase or construct additional capacity. SDG&E does note, however, that only to enhance certainty in the contract terms did it adopt a simple interest rate of 12% per annum. Further, in SDG&E's view, while its method for calculating its one-time Termination Payment B is reasonable, its complexity might require a different approach, preferably that suggested by the staff below.

(4) Staff

The staff's proposed termination provisions are designed to reflect the principles that (a) standard offers should specify the consequences of a QF's termination; (b) termination provisions should encourage QFs to fulfill their contracts, but also encourage the QF to provide sufficient notice to allow a utility to replace the lost capacity; and (c) damages for termination should be calculated to make the utility and ratepayer whole. Guided by these principles, the staff adopts an approach that is somewhat similar to those proposed by PG&E and SDG&E.

Specifically, the staff endorses the distinction between QFs which provide adequate notice and those which do not. Staff adopts the notice periods proposed by SDG&E and the general concept of the recovery of overpayments with interest calculated at the prime rate as determined by a common reference source. According to the staff, however, the additional payment required of a QF which fails to give the minimum notice should equal 50% of the amount of the capacity overpayment calculated without accrued interest. The full "penalty" should be reduced in direct proportion to the length of notice the QF gives as compared to the prescribed notice period. Staff argues that the penalty should be based on a number that is known at the time the contract is signed, not an uncertain future capacity replacement cost figure. Staff therefore bases the additional payment required of QFs who fail to give adequate notice to the overpayment to be refunded, a payment which could be calculated for different termination dates at the time the contract is signed.

Staff also urges that a probationary period like that prescribed by PG&E should be applied by all the utilities not only to failures to deliver contracted capacity, but also to failures to maintain QF status or pertinent governmental authorizations, permits, and licenses. With respect to the latter failures, the 15-month period would provide

time within which to correct those deficiencies without risking total contract termination.

The staff also argues that a QF should not be required to provide evidence of its ability to make potential termination payments. Finally, the staff recommends that the utilities should include clear examples in their standard offers of the operation of their termination provisions.

(5) Other Parties

CMA urges that the staff's recommendation of a "50% penalty" for early termination should be rejected as arbitrary. According to CMA, the QF and the utility should submit the matter to arbitration at the time of termination with the burden on the utility to show its actual damages. Other parties seem to suggest that any of the proposed termination "penalties" are arbitrary and should be rejected.

(6) Discussion

Our review of the utilities' termination provisions is not one to determine the utilities' compliance with OIR 2, since our decisions gave no specific directions in this regard, but rather the reasonableness of the utilities' proposals. In making this evaluation, we must initially decide what termination provisions should accomplish and whether those provisions should be standardized between the utilities.

On the first question, we agree with the staff that termination provisions should encourage QFs to fulfill their contractual obligations, provide reasonable certainty of the consequences of termination, and make the utility and its ratepayers whole. With respect to contract standardization, we conclude that there is no reason for the termination provisions to vary greatly between utilities with respect to the basic requirements of such provisions. The type of damages caused to a utility by a QF's termination should essentially be the same for every utility with the actual amount of those damages differing depending on each util-

ity's capacity prices. Without such consistency between termination provisions, a QF could be too greatly advantaged or disadvantaged, for no apparent reason, solely on the basis of its location.

Each of the utilities has chosen to include liquidated damage clauses in its offer. Such clauses are not "penalties" as argued by some Qfs, but are in fact an accepted method of making the party who is not terminating whole. The benefits of a liquidated damage clause include the limitation of damages to the amounts or formula prescribed in the clause and the parties' advance knowledge of how the damages for termination will be calculated. These characteristics of liquidated damage clauses make them desirable and reasonable for inclusion in a utility's standard offer for firm capacity.

We must next consider, however, what elements of a utility's damages should properly be covered by such a clause. All of the utilities have prescribed some method for reimbursement of unearned capacity payments. We believe that such reimbursement is appropriate for the reasons recited by PG&E. In particular, the utility is not required to pay more than its avoided costs for the purchase of energy from a QF. Any payment over this amount arising from price levelization should therefore be refunded to the utility.

The methods chosen by the utilities to calculate this reimbursement appear to result in essentially the same measure of repayment and are reasonable. The only element of the repayment which requires further consideration is the interest to be charged, if any, on the amount refunded. We conclude that to reflect the time value of money, an interest charge is required and further that such a charge should be determined uniformly by the utilities by reference to one source.

While various suggestions have been made, i.e., simple or prime interest rates, we believe that an appropriate

standard is that used in relation to the utilities' balancing accounts. Specifically, we have adopted the commercial paper rate as the charge on funds held in the Energy Cost Adjustment Clause (ECAC) balancing account. In doing so we have made these observations: (1) a variable monthly interest rate, as opposed to a fixed rate, reflects actual market conditions; (2) compounding of interest best reflects the actual burden on the utility and ratepayer; (3) commercial paper is the lowest cost form of short-term borrowing available to the utilities for financing undercollections; (4) the Federal Reserve Statistical Release, G. 13, is a reliable indicator of the interest rate applicable to commercial paper, prime three months; and (5) recognition should be given of the higher cost of financing for SDG&E. (D.91296, 3 Cal PUC 2d 197 (1980).) In D.91296, based on these findings, PG&E, Edison, and SDG&E were ordered to conform the interest rates applicable to their various accounts to "the published Federal Reserve Board three months Prime Commercial Paper rate (plus 50 basis points for San Diego Gas & Electric Company)". (3 Cal PUC 2d at 202.) We conclude for reasons similar to those recited above that this defined commercial paper rate is a reasonable rate to be applied to the repayments required of a QF which terminates its contract.

While we have found reasonable the utilities' provisions for reimbursement in the event of termination, we must also consider whether it is reasonable and necessary for liquidated damages associated with a utility's replacement costs to be specified in the standard offer as well. Further, we must answer whether the amount of the utility's damages should be reduced or eliminated by a QF giving advance notice of its termination. We conclude that the standard offers should include both such provisions.

As stated by SDG&E, with notice depending on the amount of capacity being reduced or terminated, a utility would have sufficient time to replace that capacity, either through purchase or construction, prior to the capacity

actually being lost. Although Edison argues that the utility will incur replacement costs at any time there is a termination, this position fails to recognize the utility's ability to mitigate these costs by being notified in advance of the termination.

We therefore adopt the distinction between QFs which terminate with prescribed notice and those which do not. The evidence in this case regarding appropriate notice periods depending on the amount of capacity being terminated is limited to the specific proposals made by PG&E and SDG&E. We believe that such a provision, however, can vary between utilities based on their best estimates of the time it will take them, given their individual operations and planning, to replace the lost capacity. We have no reason to question either SDG&E's or PG&E's notice periods. Edison, however, will be directed to prescribe a table similar to that used by those utilities prescribing varying lengths of notice for the amount of capacity being terminated up to the maximum capacity any QF could have. Thus, upon termination, QFs giving the prescribed notice will only be required to reimburse the utility for overpayments.

For QFs who fail to give the requisite notice, we find reasonable for all utilities PG&E's approach to calculating the damages to be added to the refund for overpayments. PG&E's formula is less complex than that used by SDG&E, provides certainty with respect to the QF's financial obligations upon termination, and recognizes the value of the notice which is actually given.

PG&E's proposal, however, requires one modification. Under the terms of PG&E's offer, a QF is required to pay only one year's worth of the utility's replacement costs. If the notice periods adopted by PG&E and the other utilities are a true reflection of the time which the utility needs to replace the lost capacity, the adopted damage formula should reflect that needed time. Thus, a QF which

was required under the contract to give five years' notice of termination, but only gave two, should be obligated to pay three years' worth of the utility's replacement costs. For those QFs with notice periods under one year, as provided in PG&E's standard offer, the damage formula should also be adjusted to reflect a payment of replacement costs which corresponds to the required notice period.

These modifications are necessary in part to respond to the reasonable requirement that the liquidated damage clause, as much as possible, reflects the utility's actual damages. For this same reason, we reject staff's suggestion that the utilities' references to future capacity prices be deleted from their offers and that the additional payment for failure to give adequate notice be based on 50% of the levelization overpayment. While it would certainly be beneficial for a QF to calculate its exact termination payment at the time of signing the contract, such a circumstance is not one of the principles of termination guiding our decision and, in fact, may conflict with the accepted standard of damages of making the nonbreaching party whole. The replacement costs which the utility will incur will, in fact, depend on the cost of new capacity at the time of termination, not at the time of contract signing.

We also find Edison's requirement that a QF provide evidence of its ability to make potential termination payments burdensome and unreasonable. While Edison is no doubt properly motivated to protect its ratepayers, such a provision is not a usual prerequisite in contracts and does not further the bases for termination provisions. The operating and performance standards of each of the utility's firm capacity standard offers, as modified here, are sufficient to ensure that the QFs signing these offers will be capable and dependable. It is this very group of energy producers which should be encouraged to sign offers and should not be discouraged by unreasonable contract requirements.

Staff's suggestions regarding the application of PG&E's probationary period to capacity reductions has been covered in the previous section. Whether this period also should be applied to failures to maintain certain governmental authorization is not clear. We unfortunately have no evidence to suggest how long it would take to cure such defects. Because other parties had different views and suggestions regarding provisions requiring the maintenance of governmental authorization, we will consider this entire issue in the next decision on these applications.

Because of the various formulas and notice periods to be used in the utilities' termination provisions, the staff's recommendation that the utilities give clear examples in their offers of the operation of their provisions has merit. Each utility's standard offer for firm capacity should, therefore, include such examples.

Finally, we note that a reduction, as opposed to a total termination, of capacity under a firm capacity contract is more similar to a modification of the contract than to a complete breach. Such a capacity reduction should not result in a complete termination of the agreement. The principles adopted above, however, are properly applied to such a reduction. The utilities' termination provisions should, therefore, clearly reflect their application to the amount of capacity being reduced, in the manner adopted by PG&E and SDG&E.

b. Simultaneous Purchase and Sale

In D.82-01-103 we specifically addressed a QF's ability to convert from a simultaneous purchase and sale of energy to a sale of surplus only. The concept of simultaneous purchase and sale is a regulatory convention which allows a QF simultaneously to sell its own generation to the utility while purchasing its requirements from the utility. A QF would elect this option for economic reasons (i.e., the retail rate being less than the avoided cost).

While we approved such conversions, we also imposed certain restrictions to ensure that the utility and its ratepayers are compensated for any lost capacity costs. In particular, we agreed with PG&E that such a conversion would be conditioned on reasonable notice and full compensation. The conversions were limited to once per year and were subject to the following:

> ". . .The QF that receives capacity payments under simultaneous purchase and sale through a long-term contract and converts to sell surplus will face termination provisions." (D.82-01-103, at page 86.)

Many of the QFs participating in this proceeding took issue with both the limitation on the frequency of a conversion and the application of termination provisions to that change. Given our directive in D.82-01-103, however, these issues would more properly have been raised in a petition for rehearing of that order. We further believe that the decision, which is now final, properly addressed these issues. We find no basis for changing our previous conclusions.

We note also that the termination provisions which we have adopted in this order apply to both reductions in capacity as well as a complete termination of the agreement. PG&E's contract language governing the conversion from simultaneous purchase and sale to a surplus-only sale properly directs that a QF which undertakes such a conversion will be subject to termination provisions only for the amount by which the contract capacity is reduced. Specifically, the language of PG&E's contract, Section A-3.2 of Appendix A, reads: "If the energy sale conversion results in a capacity sale reduction, the provisions in Appendix D [PG&E's termination provisions] shall apply." We believe that this approach complies with OIR 2 and should be used by all three utilities.

c. Notice of Termination in As-Available Contracts

Edison's standard offer for as-available capacity states in Section 5:

> "This agreement shall become effective on the date of execution by the parties and shall remain in effect until terminated by Seller upon one year prior written notification given to Edison, which notification shall not be given prior to the date the generating facility is operating and delivering energy to the point of interconnection."

Edison justifies the inclusion of this notice requirement as necessary for determining the number of as-available producers which, in the aggregate, will be ready and willing to sell energy and capacity in any particular year.

We reject Edison's argument. The inclusion of such a provision in an as-available contract is unreasonable and in conflict with D.82-01-103. In that order we specifically stated that termination provisions were not appropriate for offers to purchase as-available power. The staff in its brief correctly summarizes the reasoning behind this conclusion:

> ". . .Unlike firm capacity QFs, a QF with an as-available contract is under no obligation to supply power to the utility, and it is paid only for the power it delivers. The QF's incentive to produce power is its economic self-interest, not contractual penalties. Since a QF who terminates its contract is indistinguishable from a QF who chooses not to produce while maintaining its contract, staff sees little purpose in Edison's notice requirement." (Staff concurrent brief, at page 62.)

We will, therefore, direct Edison to delete the notice of termination requirement from its standard offer for as-available capacity.

B. Capacity Prices

D.82-01-103 provides that QFs which sell electricity to the utility shall be eligible for payments based on the costs that the utility system avoids through purchases of such QF power. For the standard offers which are the subject of these compliance hearings, the costs that utilities avoid by purchasing increments of QF power are defined on the basis of a short run incremental or marginal cost methodology. Short run marginal costs on the utility system consist of two components: shortage costs and operating costs. QF receive energy payments for reducing utility marginal operating costs. QFs receive capacity payments for reducing marginal shortage costs on the utility system. This section evaluates the capacity prices which PG&E, Edison, SDG&E propose to pay QFs pursuant to D.82-01-103.

In D.82-01-103 we determined that QFs should receive capacity payments for both as-available and firm sales to the utility. This conclusion reflects the fact that QF output on either basis will increase the amount of electricity available to the utility, increase reserve margins, and make the possibility of outages less likely. Stated another way, QF power will lead to avoided shortage costs and QFs should be paid accordingly.[5]

Shortage costs on the utility system at any given time can be defined as the expected cost of an outage at that time or, more precisely, the probability of an outage multiplied by the customer costs associated with an outage. As the probability of an outage increases during peak demand periods (when reserve margins are diminished) and decreases during off-peak periods, shortage costs will be higher during daily and seasonal peak periods and lower during off-peak periods. Shortages costs can also vary on

[5] As noted earlier, firm and as-available QFs do receive somewhat different payments which reflect the added value of the firm sources.

an annual basis, as reserve margins change from one year to the next.

Because customer outage costs are very difficult to measure on a direct basis, we adopted a proxy for shortage costs in D.82-01-103 and D.82-04-071. Specifically, we used the capital costs of a utility combustion turbine peaking plant, a low-capital cost plant built to meet reliability needs alone, as a proxy for annual shortage costs. This annual shortage cost amount has been allocated disproportionately to peak and semi-peak hours within the year to reflect shortage cost variations.

There is a very clear reason for adopting the capital costs of a combustion turbine as a proxy for annual shortage costs. If utilities manage their reserve margins correctly, they will pursue capacity-related investments up to the point here the last unit of investment costs the same on an annual basis as annual expected customer outage costs or shortage costs avoided through such investment. The combustion turbine represents the marginal capacity-related investment. If marginal shortage costs exceed marginal capacity-related investment costs, ratepayers will benefit by more investment which lowers the higher shortage costs by reducing the likelihood of outages. If marginal shortage costs are less than the costs of marginal capacity-related investments, then investments should be reduced, reserve margins allowed to shrink, and shortage costs to increase. Overall, the utilities will seek to equate avoided shortage costs with the annual cost of the marginal capacity-related investment (represented by the combustion turbine). The combustion turbine is therefore a reasonable proxy for the equilibrium shortage cost value that will exist on the utility system on average.

In the petitions for rehearing of D.82-01-103 the utilities argued that annual shortage costs will sometimes differ from the equilibrium or average combustion turbine capital cost level. Therefore, they argued, QF capacity prices

should vary accordingly. In D.82-04-071 (pp. 2-3), we concluded that while the use of the combustion turbine proxy "is consistent with an incremental fuel cost that will for some time be based on oil and gas", a more precise refinement of the proxy which "varies capacity payments based on the probability of loss of load, perhaps using reserve margins, would be desirable".

D.82-04-071 clearly specified, however, that as-available capacity payments were to be based on the combustion turbine and that any refinements of the proxy were to be considered only in future general rate cases. The language of D.82-04-071 was less clear as to when refinements of the proxy would be considered in the case of firm capacity payments. As noted earlier, pursuant to an ALJ ruling, the utilities were allowed to introduce into these compliance hearings methodologies for adjusting the combustion turbine proxy and the QF firm capacity payments that are derived from that proxy. Basically, the utilities' methodologies are aimed at reflecting year-to-year variations in reserve margin levels which lead to year-to-year variations in shortage costs.

The two issues before us now are (1) whether or not PG&E, Edison, and SDG&E used accurate combustion turbine costs in calculating their as-available and firm QF capacity prices and (2) whether in the case of firm capacity prices, the utilities' proposed adjustments of the combustion turbine proxy should be adopted.

1. The Cost of the Combustion Turbine

Firm and as-available capacity prices in all of the utilities' filings are based directly or indirectly on the capital costs of a combustion turbine. The accuracy of these plant cost estimates is thus an important issue in this proceeding. The threshold question here is whether or not the combustion turbine costs should be uniform between utilities, based on a "generic" combustion turbine plant, or whether the costs should be more utility-specific.

We agree with the utilities that combustion turbine costs can vary between utilities due to different financing costs, environmental requirements, and locational factors. The costs of meeting a shortage through construction of peaking capacity will legitimately vary from one utility to the next because of these factors. However, it is much less clear why other factors that are not utility-specific in nature, such as forecasts of general economic indices, should vary in the combustion turbine costs estimates adopted for PG&E, SDG&E and Edison. We do not agree with the utilities that these broader indices need to vary by utility to reflect differing corporate assumptions. If corporate assumptions about such items as inflation and oil prices had to be followed, staff and other parties could not challenge such assumptions as they normally do in other proceedings such as the utilities' general rate cases. We will allow for utility-specific cost variation where it is shown to be warranted, but will strive for uniformity in the case of assumptions that are not clearly utility-specific in nature.

The estimation of combustion turbine capital costs and the application of such costs to capacity prices in contracts of different lengths requires estimates of numerous factors. These include combustion turbine construction costs, fixed charge rates, plant economic life and book life, fixed operations and maintenance costs (O&M), fixed administrative and general costs (A&G), fuel inventory costs, escalation rates, and discount rates. We will consider these factors in the context of each of the utilities' capacity price filings.

a. Edison

Staff and IEP argue that Edison's basic combustion turbine capital cost, $415/kW, is too low, and argue instead for $450/kW based on Edison's CFM-IV filing and staff's "generic" combustion turbine estimate. Edison argues that the $415/kW number is an estimate based on a January 1, 1982 on-line date and that its CFM-IV estimate was a

"rounded" version of a combustion turbine with a June 1, 1982 on-line date. The latter is a higher figure because of inflation. We find that Edison's estimate is reasonably close to staff's "generic" turbine estimate and that it is consistent with the combustion turbine proxy that we adopted for rat design purposes in Edison's test year 1983 general rate case. Also, the January 1 number is more consistent with the average year rate base fixed charge rate methodology that is used by Edison and staff. Therefore, we will adopt $415/kW for 1982 combustion turbine capital costs for Edison.

To spread the combustion turbine capital costs to capacity prices over the years of various QF contracts, including the single year as-available contract, fixed charge rates and constant dollar factors are used. These factors depend in part on the economic life that is assumed for the combustion turbine. Edison argues that a 30-year economic life should be used. This period, in Edison's view, is a realistic estimate of the useful life of such a plant. Staff and IEP counter that Edison uses a 23-year assumption to depreciate its own plant and that a 30-year assumption is inconsistent with this approach and artificially disadvantages QFs.

We have previously considered this issue in D.93887 (p. 175), in which we decided that PG&E should use a 24-year combustion turbine useful life assumption consistent with its own depreciation schedules. Edison's assumption is inconsistent with D.93887 and with PG&E and SDG&E filings in this proceeding. We will adopt the 23-year economic life for Edison's capacity prices. Any change by Edison in its own depreciation schedules to more closely reflect its estimate of useful plant life made in this proceeding should be considered in Edison's general rate case.

Escalation and discount rates also affect the combustion turbine-based capacity price stream for different contract lengths and different start-up dates. The 15% discount rate

used by staff and Edison, based on an estimate of Edison's incremental cost of capital, is reasonable. The escalation rates for capacity prices, fixed O&M, and fuel prices used by staff are reasonable. Edison argues that these latter staff assumptions are at odds with its corporate assumptions used for planning purposes in general. We believe that these are factors which are not utility-specific in nature. The use of the staff assumptions here is consistent with adoption of the same assumptions for PG&E's and SDG&E's combustion turbine cost estimates discussed below.

The staff fuel price assumption is only important for combustion turbine cost estimation if the combustion turbine fuel inventory cost escalates over the life of the unit. Edison contends that this fuel inventory cost should not be escalated. In effect, Edison assumes that gas will always be available for use in the turbine over the life of the unit and that the liquid fuel inventory will never be used. Staff and IEP argue that the inventory costs should be escalated, using their oil price escalation assumptions. Staff argues that gas may not always be available and that even if it is, it may not be the cheaper fuel option. Therefore, the inventory will be used and replaced over time. The staff escalation rate assumption implicitly assumes that the inventory will be replaced annually.

We conclude that the most reasonable assumption lies between the staff and Edison positions. It is unlikely that the inventory will be replaced annually and such an assumption may overstate avoided fuel inventory costs, particularly since Edison normally uses first-in-first-out (FIFO) fuel inventory accounting. The assumption that the inventory will never be turned over, however, is equally unrealistic. We will adopt an escalated fuel inventory using 50% of the staff's annual escalation rates, reflecting partial annual use of the inventory over time.

Another item of contention between Edison, staff, and IEP, is the proper amount of fixed A&G costs that should be capitalized as a part of the combustion turbine costs. Edison uses 1% of the capital costs of the plant as a measure of levelized annual A&G costs over the life of the plant. Staff uses 1% of the capital costs of the plant as a measure of the first year A&G costs and escalates this figure over the life of the plant. The result is equivalent to a 1.6% levelized A&G figure. Staff argues that Edison used the 1% escalating figure in its most recent general rate case. IEP argues that at 2% levelized figure should be used, citing a 1982 staff study that showed Edison's A&G costs to be a 2% or higher percentage of fixed plant. Edison in this proceeding repudiated its rate case marginal cost A&G assumption and questioned the applicability of the staff calculations in Exhibit 16 upon which IEP relied in making its argument.

It is apparent from the record here that the relationship between A&G costs and fixed plant additions is not fully understood. We agree with Edison, however, that the degree to which A&G costs are actually avoided by QF purchases is problematic. Under these circumstances, a conservative approach is appropriate in prescribing the A&G measure. We will therefore adopt Edison's 1% levelized figure for A&G.

Staff, IEP, and Edison also disagree on the appropriateness of Edison's "differential fuel credit". Edison includes in its combustion turbine capital costs a measure of the increased fuel costs that occur, above the system marginal operating cost, when the combustion turbine is actually operated. We agree with IEP and staff that Edison should account for this increased marginal operating cost not in the combustion turbine capital cost, but in its estimate of the system marginal operating cost. In other words, the costs of operating the combustion turbine should be reflected in QF energy prices, not capacity prices.

Finally, we note that Edison in its brief argues that the staff's fixed charge rate in Exhibit 71 differs from Edison's rate for reasons other than the varying fixed charge rate assumptions of the two parties. This circumstance appears to be purely a computational problem. We will direct Edison in this order to file capacity prices that are based on combustion turbine costs that reflect our preceding conclusions about costs.

b. SDG&E

SDG&E's capacity price filing utilizes a combustion turbine capital cost of $400/kW. Staff argues, as it did in the case of Edison, that $450/kW is a more appropriate figure. Staff found the SDG&E estimate to be too low because of inadequate allowance for cost overruns, pollution control requirements, new site costs and other factors. SDG&E counters that its allowance for cost overruns is consistent with historical experience, that it has included requisite pollution control costs, and that it is unrealistic to include new site costs given that SDG&E would be much more likely to add combustion turbines at existing sites.

IEP argues that the combustion turbine cost used in SDG&E's test year 1982 rate case (A. 59788), $618/kw, should be used for capacity prices here. SDG&E states in Exhibit 37 that the rate case figure reflects a 500MW combustion turbine development at a new site with an anticipated baseload mode of operation. The OIR-2 filing reflects the avoided costs of a 50MW peaking unit at an existing site.

We will adopt SDG&E's capital cost estimate of $400/kw. It is reasonably close to Staff's "generic combustion turbine" estimate and the reasons for its being lower, such as the use of existing plant sites, are justifiable on utility-specific grounds. We agree with SDG&E that their rate case cost estimate is based on a plant type that does not sufficiently reflect the marginal peaking capacity investment that we have chosen for the shortage cost proxy.

Staff and SDG&E differ on the proper escalation rates to be used for capacity costs, fixed O&M, and fuel prices. Consistent with our discussion of the Edison combustion turbine costs, we will adopt the staff estimates. We do, however, agree with SDG&E that more recent, lower inflation rates should also lead to a lower estimate of the incremental cost of capital that is used in the fixed charge rate. We will revise the staff figure of 16.5% down to 15.5%. This approach is consistent with the estimate used for Edison while also taking into account the different credit ratings of the two utilities.

The record is silent on whether SDG&E included an A&G cost in its combustion turbine cost estimate. We agree with staff, which argues in its brief that an A&G component should be included. SDG&E A&G costs should be commensurate with those adopted for Edison.

Staff and SDG&E are in agreement on fuel inventory costs, fixed O&M costs, and the economic life of the plant. We will adopt these figures. For the purposes of calculating capacity prices, SDG&E will be directed to utilize combustion turbine costs which conform to the foregoing conclusions.

c. PG&E

PG&E filed capacity prices that were based on combustion turbine capital costs of $770/kw. This estimate was taken from PG&E's most recent general rate case. (D. 93887). Staff argues that, unless the Commission uses a generic combustion turbine cost, it would be simpler to use the rate case number used by PG&E. IEP concurs that the rate case estimate should be used, but offers several suggestions about various combustion turbine costing assumptions should the issue be considered anew.

We do consider it to be important to examine the combustion turbine cost assumptions in this decision rather than merely accepting estimates from previous rate cases.

We indicated in D.82-01-103 and D.82-04-071 that the combustion turbine was a reasonable proxy for shortage costs. The purpose of these compliance hearings was to examine the adequacy of the method by which the utilities translated this concept into capacity prices.

From the perspective of the record in this proceeding, in which three utility filings were considered together, PG&E's capital cost estimate from its rate case appears to vary from that of the other utilities by an unreasonable amount. This variance is wider than one could reasonably expect from utility-specific factors alone. Therefore, we will not adopt this estimate and will instead adopt the staff's generic combustion turbine capital cost of $450/kw for PG&E. This estimate is closer to our adopted capital costs for Edison and SDG&E.

We agree with IEP that if one combustion turbine cost estimate from PG&E's rate case is examined and updated here, other assumptions should be examined a well. We will therefore not adopt staff's use of the rate case escalation and discount rates. Instead, we will adopt for PG&E the more recent estimates for capacity price, O&M, and fuel price escalation that staff has recommended for Edison and SDG&E. We will adopt a 15.0% incremental cost of capital which is consistent with our adopted discount rate assumptions for Edison and SDG&E.

IEP notes that the rate case combustion turbine estimate did not include a fuel inventory cost. To ensure consistency, we will direct PG&E to include a fuel inventory cost component equivalent to that adopted for Edison.

We find that the assumptions used by PG&E in its rate case estimate as to the economic life of the turbine, fixed O&M costs, and fixed A&G costs are reasonable. We will direct PG&E to derive capacity prices based on combustion turbine cost assumptions adopted in the foregoing discussion.

2. Adjustments in the Combustion Turbine Proxy for Firm Capacity Payments

As noted earlier, in these compliance hearings the utilities proposed that their firm capacity prices be based on methodologies that adjust the combustion turbine shortage cost proxy for year-to-year variations in reserve margins and reliability. Staff supported these methologies in concept, but criticized several specific elements of the methods. Also, staff argued that because of the uncertainty over the accuracy of the methods and the related assumptions, a "floor" on downward adjustments of the combustion turbine proxy should be adopted. The floor capacity price in any contract year would be 50% of the annual combustion turbine cost.

IEP, Occidental, the State Energy Task Force and other QFs opposed the utilities' methodologies, arguing that they were given inadequate opportunity to examine these methods in the hearings. Further, the limited examination that did take place showed that the utilities' methodologies were seriously flawed.

We will consider all of the parties' positions in the context of each utilities' proposed shortage cost methodology.

a. PG&E

PG&E proposes that the combustion turbine proxy be set as the maximum annual shortage cost and that this value should be adjusted downward in years in which reserve margins are forecasted to be above target levels. PG&E proposes that this downward adjustment be based on an Energy Reliability Index (ERI). The ERI is derived from PG&E's Generation Reliability and System Simulation Model (GRASS). The ERI is a probablistic measure of the expected size and frequency of reduced electric energy deliveries which are forecasted to result from generation capacity limitations in future years. An ERI number is derived for each future year in which firm QF capacity prices must be calculated. In years in which

PG&E's reserve margins are expected to be smaller than or equal to target levels (with loss of load probabilities greater than or equal to the target one day in ten years), the ERI adjustment factor is set at 1.0 and the QF capacity price is set at the full combustion turbine cost level. In years in which reserve margins are atypically large the ERI adjustment factor is calculated as the ratio of the ERI in the large reserve margin year in question to the ERI in a base year when reserve margins are at their target levels. This ratio, a number less than one, is multiplied by the full combustion turbine cost to produce a QF capacity price for that year which is less than the full combustion turbine proxy.

We believe that PG&E has presented an innovative methodology for measuring shortage costs. However, we agree with other parties in the proceeding that the method is underdeveloped and suffers from several important flaws in both concept and actual application.

One important conceptual flaw is that the ERI method is biased because it allows for *downward* adjustments in the shortage cost proxy when reserve margins are above target levels, but does not allow for *upward* adjustments in years in which reserve margins are below target levels. We agree with Occidental and IEP that such upward adjustments should be a part of any precise shortage cost methodology. Clearly, as noted earlier, the combustion turbine is a proxy for the equilibrium or average shortage cost value. Actual shortage costs will vary above and below the equilibrium value, due to the "lumpiness" of powerplant capacity additions. This circumstance is especially true in the case of shortage costs for the near term, a time frame in which unexpected demand increases cannot be met with new plant additions because of the lead time associated with new plant construction. In calculations of longer term shortage costs, an upper limit equal to the cost of a combustion turbine proxy may be appropriate, depending on the precision on forecasts.

A second conceptual problem with the PG&E method is that it treats many of the uncertain factors that affect future reserve margins in a deterministic fashion. It is a basic tenet of supply planning that the greater the uncertainty about future demand levels, plant start-up dates, and plant maintenance requirements, the greater the reserve margin "insurance premium" that is needed. For PG&E's assumptions not to reflect the uncertainty about these factors is to understate reserve needs. As PG&E has stated in its CFM-IV filing:

> "The explicit inclusion of uncertainty will always require a larger reserve capacity to maintain the same level of reliability, given the assumed certain outcome falls in the middle of the range of possible outcomes . . . PG&E's (supply) planning reflects this consideration." (Ex. 68).

We agree with Occidental that, if uncertainty leads PG&E to increase its estimates of shortage possibilities and reserve needs for its own supply planning purposes, PG&E, to be consistent, should also take this uncertainty into consideration in calculating capacity payments to QFs. If this approach is not used, QF capacity value will be understated.

Another shortcoming related to the development of the PG&E methodology is PG&E's failure to perform a sensivity analysis on the ERI model to investigate whether or not the ERI results would be drastically altered by small changes in input assumptions. PG&E has argued that the ERI results are not likely to be sensitive. Staff points out in its brief, however, that the evidence indicates otherwise. The relatively small adjustment PG&E made during the proceeding in its input assumption about load management achievements led to a relatively large change in the ERI result. In general, the lack of sensitivity analysis casts doubt on the validity of the ERI results.

Apart from these weaknesses in the PG&E shortage cost methodology itself, numerous questions arose during the hearings about the application of the methodology to the standard offers. It appears that PG&E used several erroneous input assumptions when it calculated ERI adjustment factors and derived its proposed QF capacity prices. Start-up dates for the Diablo Canyon nuclear plant and the Helms pumped storage facility were assumed to be January 1, 1982, and August 1, 1983 respectively, both of which are incorrect. Future forced outage rates on plants such as Rancho Seco and Contra Cost 1 were assumed to be much less than the outage rates experienced historically. The derating of the Pittsburgh 7 plant was not taken into account. Demand forecasts were based on older, higher oil price assumptions and therefore were probably understated. Demand may have also been understated, in turn understating shortage costs, because the forecast load management goals were assumed to have been fully achieved.[6]

Forecasts of future reserve margin levels are obviously extremely difficult undertakings which involve many assumptions about future loads and resources. PG&E's assumptions were not adequately substantiated in the hearings. Many of the assumptions appear to have the effect of understating future shortage costs and QF capacity payments.

PG&E offered two revisions of its assumptions which lessen this problem to a certain degree. First, the extent of its assumed load management achievement was reduced.

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[6] We note in passing that while load management *goals* should not be included, we do not agree with Staff and IEF that load management should not be included *at all*. Rather, we concur with Edison's argument in its brief that load management, utility resources, and QF power must be considered, to the extent feasible, simultaneously, not sequentially, in the estimation of future shortage costs. However, load management assumptions must be conservative, especially when estimating the impact of voluntary programs.

Second, PG&E offered to make a retroactive upward revision in QF capacity payments if the Helms and Diablo start-up dates were not realized.

We consider the retroactive payment revision undesirable because it does not signal QFs prospectively about the value of their future performance. More importantly, we do not consider these two proposed revisions of PG&E's capacity input assumptions are sufficient to alter our conclusion that the ERI input assumptions result in understating shortage values and QF capacity payments.

Because of the methodological flaws and questions surrounding PG&E's input assumptions we will not adopt PG&E's shortage cost methodology. While we will not preclude new proposals in future hearings aimed at refining the shortage cost proxy, at this time we conclude that PG&E's firm capacity payments, like its as-available payments, should be based on the basic combustion turbine proxy, using the combustion turbine cost assumptions adopted previously in this decision.

b. SDG&E

SDG&E proposed a shortage cost methodology which is similar to PG&E's. In SDG&E's methodology, an annual "probability of need" is calculated using SDG&E's production simulation model, PROMOD. The probability of needing capacity varies from year to year as reserve margins vary. The maximum value of the probability of need is 1.0, and in such years QF capacity prices are set equal to the full combustion turbine. In years when reserve margins are above target levels, the probability of need is less than one and the full combustion turbine capacity price is adjusted downward accordingly.

In its brief SDG&E claims that certain criticisms of PG&E's method do not apply to SDG&E's methodology. In particular, SDG&E claims that it uses more realistic input assumptions in its reserve margin forecast. For ex-

ample, forced outage rates on existing units are assumed in the PROMOD forecast to be similar to those experienced historically by the plants. Forced outage rates on new units are assumed to be higher than those experienced by other utilities with plants of the same type, to provide "a cushion against error". Finally, SDG&E asserts that it *has* taken into account the impact of more recent, lower oil price forecasts in its demand forecast and reserve margin forecast.

In evaluating SDG&E's shortage cost method, it is immediately apparent that this method includes certain flaws similar to those enumerated for PG&E. For example, a basic methodological shortcoming is that the shortage cost proxy can only be adjusted downward and can never exceed the equilibrium or average combustion turbine level. Further, an increasing shortage cost trend through the years can, under SDG&E's method, never be followed by any downward trend, even if this situation more accurately reflected reserve margin changes. Finally, with respect to input assumptions, it appears that uncertainty about new plant on-line dates was not taken into consideration and that, for example, an unrealistic assumption was made about SONGS 2 being fully available by the beginning of 1982.

It is difficult to evaluate the extent to which SDG&E's method suffers from flaws in data and methodology because SDG&E's shortage cost method was not sufficiently examined during the hearings. SDG&E changed its methodology late in the proceeding after staff had already undertaken its evaluation of SDG&E's capacity prices. SDG&E did not adequately substantiate its new method and the input assumptions that it used. The ALJ ordered SDG&E on October 15, 1982 to provide data on its input assumptions and its methodology in keeping with our decision in OII-26 which set up certain requirements to substantiate evidence in cases involving computer simulations. Such information was to be provided to staff and the State

Energy Task Force during the briefing schedule. However, both staff and the State Energy Task Force indicate in their briefs that they had still not received the data at the time briefs were completed in mid-November.

Because SDG&E's methodology appears to have certain flaws similar to those found in PG&E's approach and because SDG&E did not adequately substantiate its proposed refinement of our adopted shortage cost proxy, we will not adopt SDG&E's proposal. Instead, we find that the basic combustion turbine cost is an adequate proxy for shortage costs and should be used for SDG&E's firm capacity payments. This finding is consistent with D.82-01-103, with SDG&E's as-available capacity price, and with our previous conclusions relating to PG&E's firm capacity price. As we noted in the case of PG&E's method, our adoption of the basic turbine shortage cost proxy for firm capacity prices does not preclude the further consideration of more precise shortage cost methodologies in future hearings.

c. Edison

Edison's proposed refinement of the combustion turbine proxy represents a different methodology than that proposed by PG&E and SDG&E. Rather than adjusting the combustion turbine proxy to reflect the results of computer simulations of likely future reserve margins, Edison proposed that QF capacity prices should equal the price of wholesale market capacity contracts between 1982 and 1985 and full combustion turbine costs thereafter.[7] The wholesale market price that Edison primarily relies on for

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[7] The combustion turbine costs are based on the value of deferring a combustion turbine over the length of the contract. This is a slightly different approach for deriving the levelized price for different contract periods than that used by PG&E. PG&E applies a real economic carrying charge to an annually inflating turbine cost and levelizes the resulting escalating payment stream. Both approaches should lead to the same result given the same assumptions and either is acceptable.

1982-1985 QF capacity prices is the emergency capacity price in the California Power Pool Agreement. Secondarily, Edison states that this price is also supported by the Edison - California Department of Water Resources Contract and the Principles of Interconnected Operations for the Navajo and Four Corners Power Projects. Edison contends that its $24/kW/yr 1982-1985 capacity price for QFs is quite generous. Edison points out that it would only pay such a price for emergency purchases under its wholesale contracts if it were to take emergency power for the entire 12 months of the year. In Edison's view, such a circumstance is very unlikely.

The State Energy Task Force contends that the wholesale contracts that Edison relies upon for its 1982-1985 QF capacity price are complex energy and capacity exchange agreements that involve shared services. Because it is part of such a package, the State Energy Task Force claims the emergency power price cannot be isolated and used by Edison in developing its shortage costs.

The State Energy Task Force's claim has merit. It is quite possible, for example, that, within these reciprocal exchange agreements, emergency power services are mutually underpriced by the parties to the agreement. If this is so, taking the California Power Pool Agreement as an example, then a QF which allows Edison to avoid a capacity purchase from PG&E would be avoiding Edison's capacity purchase costs and PG&E's costs which are not covered in the purchase price. The fact that the price of emergency power in the California Power Pool has not changed since 1964 despite inflation and narrower reserve margins makes this possibility quite plausible.

Edison argues that it is necessary to focus on the costs that it actually avoids when it does not make a wholesale contract purchase, not any additional value of the service that may not be reflected in the purchase price (or any additional cost that may be avoided by another utility else-

where). However, if we return to the California Power Pool example, it can be seen that such a focus may not yield accurate avoided cost price signals. If PG&E and Edison were to base QF capacity prices on a mutually underpriced reciprocal exchange service, the additional costs that QFs actually avoid, but are not reflected in the price, would never be included in QF capacity prices of either utility. This possibility weakens the validity of Edison's argument.

A second criticism of the Edison method is that the wholesale contract price is not necessarily a reasonable proxy for the utility's marginal shortage cost. The existence of wholesale contract capacity does not indicate whether or not the contract capacity represents the marginal resource. Is the contract the most expensive increment of capacity on the system (more expensive than other capacity contracts or load management programs of other resources)? Is the contract the resource that would be avoided if QF power was accepted? Even within the narrow sphere of wholesale contracts alone, it is not clear that emergency power contracts are the type of contracts that would be displaced by constant purchases of firm QF power. Under emergency power agreements, infrequent use of the service is normally assumed by the seller. Constant firm purchases might lead to a different type of wholesale agreement and price. The latter might be a better measure of avoided cost.

A clear conclusion on the accuracy of using wholesale emergency contracts as the marginal shortage cost proxy would require more evidence about all of Edison's wholesale contracts, company-owned resources, and load management programs. We are hampered in our analysis, as we were in the case of SDG&E, by Edison's inadequate offering of data during the proceeding. For example, the State Energy Task Force submitted to Edison a data request on August 27 asking Edison for information about its capacity price methodology based on wholesale con-

tracts. The information which was sought included (1) the contracts that were used to set the $24/kW/yr 1982-1985 price and (2) other contracts that exist, but were not used to set the QF capacity price. This information is exactly the type required to ascertain the validity of the price calculation and the degree to which the contracts upon which that calculation is based represents the marginal resource in the context of all such contracts.

Edison responded on September 21 that "much of the specific information sought is proprietary in nature". During subsequent hearing dates, however, it because apparent that the contracts in question are public documents filed with the Federal Energy Regulatory Commission.

In view of the doubts cast on the wholesale capacity price resulting from the reciprocal exchange arrangements upon which it was based, and in view of the inadequate showing indicating that the chosen contract price was an accurate reflection of Edison's actual avoided shortage cost, we cannot adopt Edison's proposed methodology. As we have done in the case of PG&E's and SDG&E's firm and as-available capacity price and Edison's as-available capacity price, we will adopt the capital cost of the combustion turbine as a reasonable proxy for shortage costs for Edison's firm capacity prices. This conclusion does not preclude the adoption of a more precise shortage cost methodology for Edison in future hearings and does not preclude the use of wholesale capacity prices in such a methodology.

3. Conclusions on Capacity Prices

In D.82-04-071 we concluded that: "At present the gas turbine is the best surrogate we have for capacity and it is consistent with an energy payment based on oil or gas." (Mimeo, page 3.) We reaffirm that conclusion today. In reaffirming this conclusion we do not posit that the combustion turbine is the most exact measure of avoided shortage costs. Given the evidence in this proceeding we

essentially face a choice between imperfect measures of avoided shortage costs: (1) the utilities shortage cost measure, which have been inadequately substantiated and shown to be biased downwards in certain respects and (2) the combustion turbine proxy which is also an inexact measure and has been argued to be biased upwards. Given this imperfect choice and the uncertainty surrounding avoided shortage costs, we choose the combustion turbine alternative because it gives a stronger incentive to cogenerators and small power producers. This is proper, we believe, because these power sources bring with them many important benefits to ratepayers which are difficult to quantity and not captured in the avoided cost calculation.

We will direct the utilities to file as-available and firm capacity price schedules based on the capital costs of the combustion turbine, using the combustion turbine cost assumptions adopted earlier in this decision. We also conclude that the possibility of developing a more refined shortage cost methodology which accounts for year-to-year variations in reserve margins is worth exploring further. The issue will be raised in PG&E's and SDG&E current rate cases, and in Edison's five-year forecast energy price offer (A.82-04-46). Any revisions to capacity tables will be made prospectively for new contracts. They will not apply to QFs which have already signed firm capacity contracts.

Energy Payments

A. General

D.82-01-103 stated that energy payments should be derived from a utility's shortrun operating costs, reflecting the variable cost of providing an additional unit of electricity. In calculating the energy prices, the intent of the decision was "to capture as accurately and timely as possible the current marginal energy costs incurred by the utility." (D.82-01-103, page 31.) The decision stated that the current practice was to use the previous three-month oil costs and forecasted incremental heat rates. In a later

decision (D.82-11-087), the Commission made a revision and adopted prospective fuel prices in the event that gas was the marginal fuel.

The parties in the case representing small power producers generally were concerned by the unpredictability of the energy prices and by their inability to verify the calculation of these numbers. Various suggestions were made to provide more certainty, including proposals to include formulas for energy in the contract, to use average annual incremental heat rates, to establish price floors, and to levelize the energy payments over time. In general, the utilities have rejected such proposals as being unworkable, overly burdensome, or unresponsive to changing conditions.

We resolve these conflicting concerns by ordering utilities to provide a much certainty as is possible in their contracts and procedures without undermining the basic concept of using the avoided energy price applicable to these standard offers. The risks QFs take relating to energy prices in these offers are not unlike the risks in a competitive spot market. For example, small power producers take the risk of changing utility fuel costs in future years as they influence the marginal energy rate. It is also consistent for incremental heat rates to fluctuate since, in fact, these rates will vary depending on future supply and demand conditions in utility operations.

SDG&E argues that the Commission's program to develop small power production "significantly reduces the QF's obligation to compete in an open and free market for the sale of QF generated power." Noting that "the QF receives a payment for its power from a regulated environment instead of an open market", SDG&E argues that "[t]his substantial reduction of the risk in a QF's operation, compared to an open market business operation, is an unprecedented preferential benefit provided by the State of California to unregulated businesses." (Brief, page

3.) We disagree. As described above, QF prices behave similarly to those in a competitive supply market, and the pricing does create considerable risks for QFs, not unlike those in a competitive market. In fact, our concern is that the administratively established prices in this program may create *more* risks for QFs than would open market prices. Unlike a free market, administrative changes can affect basic pricing methodologies, not just changes in supply and demand conditions. We agree with QFs that these risks should be mitigated whenever possible.

One major administrative risk implied by the proposed contracts is the possibility of a change in pricing policy by future Commissions. Specifically, as the contracts currently are written, some future Commission could order that a new pricing policy be adopted with prices derived at less than avoided costs. We do not believe such discretion is appropriate. While a future Commission may have the prerogative to implement pricing policy changes prospectively for new small power contracts, QFs which have already built projects should received payments derived from the pricing methodology in existence when the project was built. Otherwise, far too much price uncertainty will exist. Accordingly, we will order that utilities include a provision in all their standard offers before us which assures QFs that they will receive payments throughout the life of the specific project derived from the utility's full shortrun avoided energy costs, as approved by this Commission. This requirement will ensure that a framework is established firmly, with prices derived from a utility's full avoided costs. Since these contracts are viewed as reasonable, per se, the utility's expenses for such purchases can be assured (D.82-01-103, page 24). Such a provision does not add to utility risks as suggested by the utilities.

The second major administrative risk for small power producers not present in a competitive market is the model used for calculating the avoided cost payment. Unlike most

markets in which buyers and sellers meet at arm's length to establish prices (i.e., the stock market or a commodity market), the prices established for small power producers are derived from models in possession of the utilities as approved by this Commission. Not surprisingly, the small power producers are skeptical of this arrangement and would at least like these models to be more explicit and understandable. We agree that this concern is significant. We will therefore require that utilities present, in detail, the assumptions behind their energy price calculations and that QFs have an opportunity to critique the assumptions in the utility models.

To provide greater certainty and clarity, some QFs suggest that an energy price formula be written into the QF contract. We do not find such an approach to be feasible. The pricing formula is highly complex and could not suitably be incorporated. Furthermore, while QFs should have the certainty that their prices will reflect the utilities marginal variable costs, the actual model for calculating such costs may become more refined in the future. A specific formula would preclude such refinements. By clearly establishing that prices should reflect the utilities' shortrun avoided costs in the contract and by giving QFs an opportunity to review and comment on the utilities' calculations, we believe sufficient certainty is provided as to how these payments are to be derived.

B. Determination of Energy Prices

While the policy to establish prices from the utilities' shortrun marginal operating costs is generally understood, there remains a considerable debate on how to calculate those rates. The utilities' marginal operating costs vary almost continuously, and at least at this time the metering technology does not exist to signal prices so frequently. As a result, the *average* marginal cost applied for a particular time period must be used. One issue concerns how long this periods should be and under what conditions the

prices may be adjusted from the average marginal rates. A second major issue concerns whether the methods used by utilities for calculating the marginal operating costs for a particular period are accurate.

We generally resolve these issues in two ways. First, to the extent possible, this decision addresses the specific concerns raised by the parties relating to the calculation of energy prices. However, it is clear from this proceeding that not all of the potential issues relating to the calculation of energy prices were addressed. We expect that the parties will want to offer further comments and refinements in the future. Therefore, in addition to resolving many specific issues here, we will provide a procedure by which QFs and other parties can provide comments in the future. We do not provide this procedure as a forum to relitigate issues, but to allow new issues to surface. Small power producer pricing remains in an evolutionary stage, and we have not doubt that issues will continue to arise about how prices should be established within the guidelines established in D.82-01-103.

1. Incremental Heat Rates

One significant issue in this case was how often a utility's incremental heat rates should be revised for determining prices to small power producers. Incremental heat rates, which reflect the efficiency with which utilities can burn fuel at the margin, are one component in the determination of the marginal cost of electricity. IHRs vary depending upon what plants are in operation at any particular time.

Currently, incremental heat rates are determined biennially in the utilities' general rate cases, with heat rates varying by time of day and season. These incremental heat rates are used for determining the prices during the two-year period after a rate case is completed, using fuel costs which are updated quarterly (for PG&E and SCE) or three times a year (for SDG&E). If actual incremental heat rates

deviate from the projected average heat rate developed in a rate case due to hydro conditions or any other reason, this change is not reflected in the quarterly prices.

QFs generally favor using the average annual heat rate approach because it provides more price stability. Administratively, QFs also object that utilities may deviate from the average annual heat rate when it suits their interests (e.g., when hydro conditions are favorable and the incremental heat rates generate relatively low prices). PG&E suggests that average annual heat rates be used now, but suggests that projected actual year heat rates (accounting for hydro conditions) might be desirable in the future to more closely reflect actual shortrun operating costs.

By separate petitions for modification filed September 10, 1982, CMA and Imotek, Inc. asked the Commission to clarify D.82-01-103, and find that utilities should use average annual incremental heat rates for determining avoided costs, as determined in the most recent rate case. The petitioners argue that actual year heat rates create instability in QF prices and are unverifiable. We will respond to this petition in this opinion.

We resolve that, for now, average year incremental heat rates should be used in the determination of avoided costs as determined in the utilities' rate cases. We have no procedure at this time for verifying more current estimates, and we do not think it appropriate to adopt more frequent estimates without giving parties the opportunity to comment on the methodology. However, we conclude that actual year incremental heat rate calculations would be preferable because they more accurately reflect actual marginal operating costs. QFs that are able to respond to the higher price signal in a dry year, for example, would have a greater incentive to provide energy when it is more needed. On the other hand, small hydro producers whose fluctuations in electric supply parallel those of utility hydro plants are likely to be overpaid using average hydro years,

as in the current method, since they would be likely to produce relatively little in low hydro years (when actual avoided costs are relatively high) and relatively more in high hydro years (when actual avoided costs are relatively low).

While we are adopting average annual heat rates now, we will ask utilities by September 30, 1983 to make proposals for a procedure to use projected actual year incremental heat rates. The utilities in their proposals should clearly set forth how they intend to forecast hydro conditions which would then be used to forecast actual year heat rates. The IHR forecasts probably should be made in the spring to take into account hydro conditions. We will not adopt any proposal until parties have had an opportunity to review and comment on it. Utilities should not deviate from the current two-year review procedure until the deviation has been expressly approved by this Commission.

Another issue raised by staff was how to handle new plants that come on line which effect IHRs. D.82-01-103 at page 31 states that IHRs determined in rate cases should not include new power plants because both the operating dates and operational characteristics of new plants are generally unknown. However, should a new facility begin operation between cases, staff recommends that the IHRs be revised in an ECAC proceeding. We will adopt this suggestion.

Both SDG&E and Edison argue that they should not file incremental heat rate data since such data are not explicit outputs of their models. The utilities use probablistic models, which predict the likelihood of a particular plant being on line in any particular hour, and estimate the expected average electricity price based on that model. At some cost the models could be adapted to produce incremental heat rates as outputs. We agree with small power producers that such information would be valuable

and should be provided. Current and expected heat rate data would provide QFs with the ability to determine more realistically prices in future periods. Such costs currently are included as utility administrative expenses. Such accounting would appropriate in this case.

2. Marginal Fuel Costs

Many of the parties were concerned with the fuel costs used in determining the avoided energy costs. Concerns were raised whether forecasted fuel prices, prior period fuel prices, or retrospective prices should be used and how the determination of the marginal fuel at any particular time would be made.

Currently, the energy prices are set by utilities at the beginning of a quarter, and QFs can anticipate that payments will be based on those prices throughout the quarter, except for SDG&E which establishes rates three times a year in ECAC. Adjustments are not made at the end of the quarter to reflect actual conditions during that quarter. This procedure gives QFs a clear and predictable price upon which they can base operations for future periods, but it also results in a relatively less accurate determination of the shortrun operating costs than if prices were established retrospectively with fuller knowledge of what actually occurred. Some suggestions were made in the proceeding that the prices be adjusted at the end of the quarter to reflect actual prices paid during the quarter for fuel. Payments to QFs would be retroactively adjusted at the end of the quarter to coincide with actual fuel prices paid during that quarter.

We conclude that the current procedure of prospectively establishing prices is preferable. This procedure gives QFs a clear price signal from which to determine its operations for the upcoming quarter. In reaching these prospective determinations, we will attempt, as accurately as possible, to project the fuel mix which will occur in the future quarter. Any variations in the projected price should likely

be as high as they would be low, and deviations should cancel out over time. Retrospective adjustment would undoubtedly create significant controversy, be cumbersome and destabilize the market for small power producers.

In D.82-11-087, the Commission ordered the utilities to use current natural gas prices for the determination of prospective avoided operating costs, but to continue to use oil into inventory when oil is the marginal fuel. We will continue to adopt this approach for now, though we would consider refining the oil and natural gas price numbers to include projections instead of current prices in the future. For now, we conclude that projecting oil and natural gas prices would be unduly complicated.

A major controversy in this case was the determination of whether oil or gas is the marginal fuel at any particular time. In recent months, oil in inventory has been more expensive than natural gas. QFs have been concerned that utilities have been burning oil while claiming that natural gas is nearly always the marginal fuel. In response, utilities argue that they must burn oil in inventory either to avoid underlift payments or for various other reasons which preclude oil from actually being the marginal fuel. IEP questions the utilities' assertions and suggest, as a simplifying assumption for calculation, that oil should be presumed to be the incremental fuel on any day it represents 10% of the generation mix. Staff in evaluating this issue concludes that oil is not generally an avoided fuel at this time, and that the 10% oil mix assumption is arbitrary.

It appears that the question of whether oil or gas is the marginal fuel will involve specific issues that vary in each quarter. Accordingly, our approach will be to ask each utility to file its projected marginal fuel mix in each quarter and allow parties an opportunity to critique these projections. Each quarter the utilities should also submit information on their actual experience in the prior quarter. Any

decisions reached by the Commission to modify these prices should provide guidance for future quarters.

Much time was spent in this proceeding on the issue of whether Edison avoided oil in the first quarter of 1982 or whether it primarily avoided gas. As some of the parties point out, the resolution of this issue has implications for future quarters as well. Edison argues that while oil was burned during this past year, it was not marginal because it was burned either for testing or to avoid underlift charges in Edison's long-term contracts.

Edison's response appears to be accurate. We conclude that the basic conceptual problem is that the oil prices used in the determination of avoids costs are based on long-term contract prices and therefore may not reflect current fuel markets. When a utility avoids burning oil, it may not be able to avoid the full long-term contract price paid for it when it must either sell the oil on the spot market at a price less than the contract price or refuse to take additional oil from its supplier to control inventory and pay underlift charges. It appears to be reasonable that the avoided cost therefore should be based either on the spot market price or the long-term price less the underlift charge. The utilities apparently simply assumed that the avoided cost of oil was less than gas when underlifts are taken into account and therefore assumed that their avoided fuel was natural gas. Given the current oil and gas mix and the current price relationships, such a simplifying assumption seems reasonable.

We cannot agree that oil should be presumed to be the incremental fuel when it is 10% of the daily use. Such a standard would be arbitrary. We are sympathetic to a more detailed analysis of marginal oil use in future proceedings in the determination of the marginal energy costs. The issue of whether oil or gas is the marginal fuel is complex and will depend upon specific circumstances. This issue is one that we would expect to arise in future pro-

ceedings to review the utilities's price offers, which we describe below.

Another issue in the proceeding is whether the fuel used to warm-up facilities should be viewed as marginal and calculated in the avoided cost payment. We agree with staff that the cost of warm up fuel cannot be included at this time since it is unclear that such fuel is avoided as a result of purchases from QFs.

Another issue relating to fuel costs is whether SDG&E should use its G-61 commodity rate for determining the avoided natural gas costs for its electricity utility generation. The staff and others recommend that the higher GN-5 rate be used, which is the rate established for pricing between SDG&E's gas and electric departments. The G-61 rate is the general commodity rate which SDG&E purchases all of its gas requirements.

We conclude that staff's position is correct. When the electric department of SDG&E purchases electricity from a QF, ratepayers avoid electric production with costs derived from the GN-5 rate for the purposes of calculating SDG&E's electric rates. By establishing QF prices using the GN-5 rate, ratepayers are indifferent between purchases from QFs and utility generation, consistent with avoided cost principles. To base prices on the G-61 rate would result in an underdevelopment of QF resources, leading to uneconomic use of natural gas in utility boilers. Use of the G-61 rate would also result in an inconsistent pricing system between QFs in Edison's and SDG&E's territory. Edison purchases gas from Southern California Gas Company at the GN-5 rate.

Utilities argue that fuel is not avoided when it is being burned to maintain spinning reserves. By definition, we agree. In the event fuel is being burned in the facility to allow it to be available for future periods, the availability of QFs does not allow the utility to avoid that fuel.

It is evident that the determination of the marginal fuel costs for utilities will remain a controversial subject and that the parties will want to be involved in reviewing the utilities determinations. As CMA points out, the dollars involved are large and will undoubtedly grow in the future as the QF market develops. It is important that we establish an understandable and balanced forum in which parties can review and comment on these prices.

We will therefore adopt the following procedure. In the case of PG&E and Edison, we will order the utilities to file prices for energy payments one month prior to the quarter in which the energy prices apply. These prices and a detailed description of the assumptions used to derive them should be filed with the Commission. In addition, the utility should make available this information to interested parties for their review. In the event either staff or the interested parties object to the proposed prices, a motion to adjust the price may be filed to the Commission. In the motion, the specific concern must be stated and a recommended resolution suggested. The Commission will decide what further action to take depending upon the nature of the motion.

In the event no action is taken by the Commission by the time a quarter begins, the utilities' prices will go into effect. These prices may be adjusted upward and applied retrospectively in the event the Commission later reaches a determination that the prices posted were too low. However, no downward adjustments will be made retrospectively to avoid pricing uncertainty for QFs.

SDG&E currently is establishing its prices three times a year in ECAC proceedings. We will continue this procedure. Like Edison and PG&E, SDG&E should spell out the assumptions used in deriving its numbers.

We expect utilities to forecast as accurately as possible their actual marginal operating costs for future quarters, including their expected fuel mix, and to provide their

assumptions to interested parties. We expect that as we reach decisions relating to various issues regarding price in the future, utilities will incorporate those decisions. Over time the utilities' procedures should become fairly understandable and routine. We have no doubt that parties will question utility determinations, and we expect to review them carefully. However, we do not intend to relitigate issues in proceeding after proceeding.

For this procedure to work, it is incumbent upon utilities to present their information clearly and understandably. QFs must be able to understand how prices are being determined to make intelligent investment decisions. We expect that utilities will keep all data relating to QF prices well organized in a central place to permit parties to review the calculations.

C. Adjustments to Energy Prices

A number of issues were raised in the proceeding regarding adjustments to energy prices for various purposes. We consider these issues in this section.

1. Avoided Transmission and Distribution Costs

Little or no evidence was presented in this proceeding demonstrating that QFs allow utilities to avoid transmission and distribution system costs. Therefore, none are included in the avoided cost payments filed by the utilities. We find this approach to be appropriate at this time.

2. Variable Operations and Maintenance Costs

There was general agreement that variable operating and maintenance costs should be included in the avoided cost determinations. However, PG&E and SDG&E include these costs in their energy payments while Edison includes them with its capacity payment. For consistency, we will order that these costs be included as part of the energy payment. In the regular price filings, the assumptions regarding the derivation of variable C&M should be included.

3. Line Losses

D.82-01-103 ordered applicants to "include costs or savings from line losses in the aggregate" (Ordering Paragraphs 6(a) and 8(e)). The Commission created an exception that line losses will be examined individually for "projects one MW or larger developed at sites remote from load centers."

The record in this proceeding indicates that this issue inadequately studied by the utilities to determine appropriate loss rates. PG&E's study does not differentiate between remote sites and other QFs, while SDG&E and Edison have not undertaken a study at all. In the absence of such a study, we will adopt a loss factor of 1.0 to be applied by all utilities for all QFs at this time. This resolution essentially assumes that QFs line losses are equal to utility plant losses, which seems reasonable lacking better information. We will also adopt the suggestion that loss factors be established for three voltage levels.

Additionally, we will adopt the staff position that studies be performed by utilities to determine the aggregate line losses of QFs. PG&E should report on this subject in 6 months and SDG&E and Edison in one year.

The record indicates that at this time adjustments for line losses for remote sites is beyond our current capabilities. We will therefore suspend the use of specific line losses for remote sites until the problem is better understood. As part of the studies required of utilities, we will ask for an analysis of how to identify remote QFs and how to reflect a different loss rate. Until such studies are performed, remote QFs will not have individual line losses adjustments.

PG&E suggests that individual line losses should be established. This approach would not comply with D.82-01-103. The individual determination of line losses would create great complexity and would very likely result in fre-

quent disputes between the utility and QFs. Aggregate line loss determinations are appropriate at this time.

4. Transformer Losses

An issue was raised about whether transformer losses should be included in the avoided cost payment, and if so, how that loss should be determined. The staff suggests an appropriate solution: simply place the meter on the utility side of the transformer, thereby automatically accounting for the transformer losses in the meter reading. We will adopt this recommendation. If a QF desires to have a meter on its side of the transformer, it may negotiate a transformer loss rate with the utility.

D. Refusal to Purchase and the Hydro Spill Rate

One of the more complex issues relating to energy payments regards the periods in which a utility may refuse to purchase from QFs or offer lower prices to reflect current conditions in the utility system. As described earlier, price is established for electricity purchases for a time period based on projected average marginal costs. The actual avoided costs incurred will vary throughout the period, varying around the average established.

There are certain conditions in which the actual avoided costs deviate so significantly from the average that special treatment may be warranted. In particular, D.82-01-103 found that when the utility actually incurs costs by purchasing energy from a QF (a "negative avoided cost" condition), the utility should have the right to curtail QFs. In D.82-04-71, the Commission also concluded that when a utility must spill water over its own hydroelectric facilities in order to purchase from QFs, a lower price is appropriate. The decision did not, however, permit a lower price to be established during periods when economy energy is purchased or when avoided costs are positive. Anticipated economy purchases were to be averaged in the avoided cost applied for the entire time period.

Allowing utilities to pay lower rates or curtail customers unexpectedly creates significant complications for QFs because of unwieldy notification requirements and price instability. It is also very difficult to establish what the lower rate during periods of economy energy or hydro spill should be. For this reason we previously decided to very narrowly define the period and to include the expected economy energy purchases in the average rate for the entire period. What is lost in precision is gained in administrative workability and price certainty.

The parties in this proceeding suggest alternatives and refinements to this approach. Certain QFs suggest fixed limits on the number of hours that they can be curtailed or offered the lower hydro spill rate. A number of proposals were made to limit the applicability of curtailment and hydro spill conditions. Staff proposed that a 100-hour limit be established for curtailment and hydro spill conditions, while the IEP suggested that a total of 200 hours be applied to both. Staff suggested that in the event the QF is required to curtail more than 100 hours, it should be paid for the additional hours based on what it would have produced in event curtailment had not been invoked. Staff argues that it is unlikely that QFs would be curtailed for longer than 100 hours in any event, and the added certainty about being paid makes the provision worthwhile. Utilities, in general, oppose such restrictions in the contract, arguing that such provisions would be inconsistent with D.82-01-103 and could tend to overpay QFs.

Procedurally, we agree with the utilities that restrictions on the number of hours that curtailment and hydro spill conditions apply would be inconsistent with D.82-01-103 and D.82-04-071. Those decisions attempt to very narrowly define the conditions in which either term could he applied in order to reduce uncertainty for QFs. However, lacking any evidentiary basis, neither placed limits on the application of those provisions.

While we are sympathetic of the concerns of QFs that they must understand what the outside limit of the application of these provision could be, we have no evidentiary basis to determine what that limit should be. We will, therefore, order utilities to undertake studies to estimate the maximum probable limit for hydro spill and curtailment conditions likely to occur in future years in order to provide QFs with more certainty about the likelihood of those provisions being imposed. These studies should be submitted to the Commission and provided to parties within 3 months. Based on these studies, we will entertain proposals to modify D.82-01-103 to establish limits in the contracts for the refusal to purchase and the hydro spill conditions.

1. The 600-Hour Curtailment Option

Utilities have suggested that as an option, QFs be offered a curtailment provision that applies to periods of economy energy purchases and which includes a 600-hour annual limit. While we welcome and encourage such an offer being available as an option, the offer itself is outside the scope of these compliance proceedings. The standard offer should be based on the negative avoided cost and hydro spill conditions outlined in the original decisions. We will view the 600-hour curtailment provision option as a nonstandard contract for now because we have not reviewed the details of how the curtailment provisions would work or how they would affect the marginal energy prices. We support the concept, because it would provide greater pricing precision, and permit greater economy energy purchases.

2. Implication of curtailment on Firm Capacity Payments

An issue arose on how curtailment provisions relate to the firm capacity provisions. We conclude that QFs should be presumed to be available during curtailment periods and should be eligible for any output payments (even if not actually provided) since the QFs are being curtailed

by the utilities. We will therefore adopt the staff's suggestion that the contracts be modified to reflect these conclusions. This resolution comports with D.82-01-103 at page 81, which states that QFs signing firm capacity contracts should be paid for capacity during times of non-purchase.

3. Internal Use of Energy During Curtailment

Certain parties suggest that cogeneration facilities operating under simultaneous purchase and sale contracts be permitted to use energy internally in the event of curtailment. We reject this proposal. As staff points out, curtailment is likely to occur in periods of extremely low demand, and any further reduction in demand caused by internal use of electricity would likely reduce the value of curtailment and be costly for the utility. If a QF agrees to sell all of its output under simultaneous purchase and sale, the output should be subject to curtailment as for any other QF.

4. Notice Requirements

In order to assist QF planning, longer notice requirements for curtailment were suggested. D.82-01-103 established notice guidelines. We do not see any reason to change them here. Of course, utilities should give as much notice as possible of impending curtailment.

E. Price Floors and Levelized Payments

Suggestions were made in this proceeding to establish a price floor for energy payments and to levelize energy payments. Both of these suggestions are clearly outside the scope of these compliance hearings. The levelized payment option was addressed and rejected in D.82-01-103 (Pages 55-56) and the floor concept was not discussed at all.

If a floor price were established, some reduction of the energy price would be necessary to remain within the avoided cost concept. The floor reduces QF risks and cre-

ates the possibility that at some point the floor price paid might be above avoided cost. In return for this security, a lower price during the rest of the time is appropriate. We would encourage utilities to negotiate nonstandard contracts with floors or levelized payments if QFs are interested.

Further Modifications of Contracts

This decision is the first in these applications. We will issue later in 1983 another decision regarding other issues raised in this proceeding which may result in further modifications to these contracts.

QFs interested in signing contracts between now and the time of a final decision may be reluctant to sign until the Commission resolves the remaining issues. To relieve this uncertainty somewhat, we will give QFs who sign contracts between the effective date of this decision and the time a final offer stemming from these compliance hearings takes effect the opportunity to switch from the interim contract to the final contract. QFs may not switch from one standard offer to another, but may adopt the final version of the particular offer signed.

Findings of Fact

1. The California Public Utilities Commission has a continuing interest in promoting the development of cogeneration and small power production facilities.

2. By D.82-01-103 in Order Instituting Rulemaking (OIR) 2, each electric utility was required within 45 days of the effective date of that order to file standard offers to be made to qualifying facilities for (a) as-available energy and capacity based on a short-run avoided cost methodology, (b) firm capacity based on a short-run marginal cost methodology, and (c) energy and capacity provided by QFs below 100 kW in size.

3. The offers required by D.82-01-103 were included in the applications which are the subject of this order.

4. Evidentiary hearings were held with respect to A.82-03-26 (PG&E), A.82-03-37 (Edison), and A.82-03-78 (SDG&E) to determine each of these utilities' compliance with the requirements of D.82-03-103 and other related orders in OIR 2; the reasonableness of provisions included in the utilities' offers, but not specifically addressed in the OIR 2 decisions; and the factual bases for the prices contained in each of the standard offers.

5. Consideration of issues recited in Finding 4 above for A.82-03-62 (Sierra Pacific Power Company), A.82-03-67 (Pacific Power & Light Company) and A.82-04-21 (CP National Corporation) have been deferred until the resolution of A.82-03-26, A.82-03-37, and A.82-03-78.

6. An additional issue properly addressed during the evidentiary hearing was the appropriate methodology for determining capacity costs, based on the shortage cost concept, under a utility's firm capacity standard offer. Revisions of the methodology for calculating a utility's as-available capacity payment is reserved for the utility's general rate case as specified in D.82-04-071.

7. For a decision to be issued in this proceeding prior to the end of 1982, only certain issues raised during the hearings and in briefs can be addressed. The remaining issues which are not resolved by this order will be considered as early as possible in 1983.

8. The issues chosen for consideration in this order relating to the utilities' capacity and energy payments will provide QFs with sufficient options to make the economic decisions necessary for determining the merits of proceeding with or continuing a particular project.

9. Payment for as-available capacity do not reflect any value for contract length, notice, termination or sanctions, since such provisions are not part of an as-available offer.

10. Firm capacity is viewed as an increase in the utility's supply of electricity with corresponding performance standards, termination provisions, and sanctions.

11. D.82-01-103 requires that (a) firm capacity payments reflect availability during system peak periods including such factors as dispatchability; reliability; contract duration, termination, and sanctions; scheduling of outages; and availability during emergencies; (b) the value of each of these factors are to be calculated based on standards comparable to performance standards the utility would impose on its own plants; (c) the sum of each of these factors are to be included in the resulting capacity value; (d) a QF that exceeds operating standards normally expected of utility plants is to be able to earn a higher capacity payment; and (e) when resource limitations exist to reliable operations, plant capacity factor may be a better measure of reliable operation than availability.

12. Each of the utilities proposed a different approach to performance standards in their firm capacity standard offers.

13. Three general types of performance standards have been proposed in the utilities' filings—the first based on a level of peak period availability (PG&E's Option 1), the second based on a level of peak period output (PG&E's Option 2, SDG&E's Option 2, and Edison's single option), and the third requiring only a certain contract duration with no specific requirement for peak period output or availability (SDG&E's Option 1).

14. PG&E's Option 1 availability standard requires the QF to be dispatchable and available during emergencies and to maintain a certain level of peak period reliability. The option also imposes termination provisions for nonperformance and allows for scheduled maintenance.

15. As modified herein, PG&E's Option 1 is reasonable and in compliance with D.82-01-103.

16. PG&E's Option 2 output standard ensures reliable operation during peak periods and emergencies and, like Option 1, imposes termination provisions for nonperformance with an allowance for scheduled maintenance.

17. As modified herein, PG&E's Option 2 is reasonable and in compliance with D.82-01-103.

18. An 80% summer peak hour availability or output requirement under PG&E's Options 1 and 2 is reasonable and, with PG&E's revised reduction of payments provisions, is a sufficiently flexible measure of QF performance.

19. SDG&E's Option 2, an output-based performance offer, requires only a 50% level of output during all peak and semi-peak hours. This standard of performance is not commensurate with the utility plant avoided by QF purchases, which plant would have a higher level of peak period availability than 50%. Additionally, termination provisions are not imposed for failure to meet this standard.

20. SDG&E's Option 2 is not in compliance with D.82-01-103.

21. Edison's output-based performance standard fails to focus on peak-period availability, with a 50% performance level which is too lenient for the peak period and an emergency availability requirement which is too stringent and places too much emphasis on one aspect of peak period availability.

22. Edison's output based performance standard is not in compliance with D.82-01-103.

23. SDG&E's Option 1, which merely requires a contract commitment for a specified period with no peak period availability or output requirement, fails to reflect the performance standards for firm capacity offers required by D.82-01-103 and is not an option to purchase firm capacity as defined by that order.

24. SDG&E's Option 1 is not in compliance with D.82-01-103.

25. It is necessary for the utilities to refile their standard offers for firm capacity to conform to D.82-01-103.

26. To comply with D.82-01-103, all utilities must file standard offers with payments options based on both a QF's availability and energy production. PG&E's Options 1 and 2 serve as basic models for such options, as modified consistent with this decision.

27. To achieve overall compliance with D.82-01-103 and this order, the following principles should be incorporated in any utility's firm capacity standard offer:

a. Dispatchability must be defined to give a utility the right to require only increases, not decreases, in a QF's operation. Any other definition permits unwarranted and unreasonable interference with a QF's operations. Dispatchability need not be limited to on-and midpeak periods and emergencies if an approach like that used in PG&E's Option 1 is adopted.

b. Each payment option must provide for payments in excess of a utility's capacity costs for QFs whose performance exceeds that of the utility's plants. To receive the higher payment, the QF's performance must consistently exceed the minimum level of availability of the peaking unit used as a proxy to calculate the utility's shortage costs. A peak period availability or capacity factor in excess of 85% is a reasonable performance standard to require of QFs entitled to capacity payments in excess of 100% of the shortage cost proxy. An 80% reliability factor is reasonable for offers based on 100% of a utility's capacity costs. For an availability option which permits the higher

payment, a more certain measure of the QF's dispatchability is required than presently provided in PG&E's Option 1 in order to determine whether and at what level the QF actually exceeds the utility plant's operation.

c. PG&E's proposal with respect to the treatment of small hydro QFs whose payments are based on the five dry year average,but are experiencing a "drier" year than that average, is reasonable and should be adopted for all utilities with one modification. It is reasonable to permit hydro QFs to be paid during the "drier" year for the amount of capacity, if any, actually delivered to the utility. Capacity payments should resume at the contract price when hydro conditions once again reach the level used to determine the capacity rating.

d. Essential elements of a scheduled maintenance standard are a reasonable allotment of days for both routine maintenance and major overhauls, sufficient notice to aid utility system planning, and appropriate timing to avoid periods of greatest demand on the utility system. The scheduled maintenance allowance should be uniform for all utilities and should include all of the elements and requirements listed in the discussion of scheduled maintenance in this decision.

e. PG&E's revised approach for reducing payments under either its availability or energy output payment options for nonperformance is reasonable and should be adopted in all utility standard offers for firm capacity. This modified approach permits payments for capacity actually delivered during a 15-month probationary period with the potential of the orig-

inal payment level being reinstated or the QF's capacity derated at the end of the period depending on the QF's performance during he peak months. The difference between the contract capacity and the reduced capacity is appropriately subject to contract termination provisions. For the capacity actually delivered during the probationary period, an allowance or credit for forced outages at the level otherwise specified in the utility's standard offer should be included. No retroactive payment is necessary.

28. No provision is required in a firm capacity standard offer to permit as-available capacity payments during a start-up period. A QF seeking as-available capacity payments during the period before its firm capacity operations commence has the option of signing a short-term as-available capacity contract.

29. Each of the utilities properly responded to D.82-01-103 by including termination provisions in their firm capacity standard offers.

30. The utilities' termination provisions must be reasonable.

31. Termination provisions should encourage Qfs to fulfill their contractual obligations, provide reasonable certainty of the consequences of termination, and make the utility and its ratepayers whole.

32. There is no reason for termination provisions to vary greatly between utilities with respect to the basic requirements of such provisions.

33. Liquidated damage clauses, which limit damages to the amounts or formula prescribed in the clause and provide a party with advance knowledge of how the damages for termination will be calculated, are desirable and rea-

sonable for inclusion in every utility's standard offer for firm capacity.

34. It is reasonable for the liquidated damage clause to cover reimbursement of unearned capacity payments. The utilities' methods for calculating this reimbursement are reasonable, with the exception of the need for a uniform imposition of and standard for interest to be charged on the amount refunded.

35. The published Federal Reserve Board three months Prime Commercial paper rate (plus 50 points for SDG&E) is currently used to calculate interest on the utilities' various accounts and is a reasonable rate to apply to the repayments required of a QF which terminates its firm capacity contract with prescribed notice.

36. It is reasonable for the utilities to include liquidated damage clauses to cover the replacement costs associated with QF termination and to provide a reduction or elimination of those damages for a QF which gives the prescribed advance notice of its termination.

37. Each utility's standard offer for firm capacity must distinguish between those QF's terminating with prescribed notice, for which replacement damages are eliminated, and those which do not.

38. The specific notice required for termination should depend on the amount of capacity being terminated and may be utility-specific. The proposals of SDG&E and PG&E are reasonable; Edison should be required to prescribe a table similar to those proposed by PG&E and SDG&E varying the length of notice according to the amount of capacity being terminated.

39. For QFs terminating without prescribed notice, it is reasonable for all of the utilities to adopt PG&E's approach to calculating the damages to be added to the refund of overpayments, with one modification. The adopted

damage formula should reflect the time needed, as reflected in the notice table, to replace the lost capacity.

40. The utilities' calculation of damages can properly refer to future capacity prices.

41. Any requirement that a QF provide evidence of its ability to make potential termination payments is burdensome and unreasonable.

42. It is reasonable for each utility's firm capacity standard offer to include examples of the operation of its termination provisions.

43. A reduction in capacity should not result in a complete termination of an agreement; however, the termination provisions can be applied to the amount being reduced.

44. D.82-01-103 clearly provides for a limitation of one year to conversions from the simultaneous purchase and sale of energy to the sale of surplus only and for the application of termination provisions to QFs which undertake such a conversion.

45. It is reasonable for a utility to provide that a QF which undertakes the conversion referred to in Finding 44 above be subject to termination provisions only for the amount by which the contract capacity is reduced. This approach complies with D.82-01-103 and the application of termination provisions to capacity reductions. It should be used by each of the utilities.

46. Edison's inclusion of a notice requirement for the termination of an as-available capacity contract is unreasonable, is in conflict with D.82-01-103, and should be deleted. That decision specifically states that termination provisions are not appropriate for offers to purchase as-available power.

47. For the standard offers that are the subject of these compliance hearings, D.82-01-103 requires that avoided

costs be defined according to avoided short-run marginal costs. One component of this definition, avoided shortage costs, should be the basis for firm and as-available capacity payments.

48. In D.82-01-103 and D.82-04-071 the Commission adopted the capital costs of a combustion turbine as a proxy for shortage costs.

49. D.82-04-071 specified that as-available capacity payments are to be based on the full cost of the combustion turbine and that any refinements of this proxy would only be considered in future general rate cases.

50. Pursuant to an ALJ ruling, the utilities were allowed to introduce into these compliance hearings methodologies which adjust the full combustion turbine shortage cost proxy for firm capacity payments.

51. Combustion turbine costs vary from one utility to another because of different financing costs, environmental requirements, and locational factors.

52. It is not reasonable for estimates of combustion turbine costs calculated at a given time to vary from one utility to another on the basis of general economic indices.

53. Edison's combustion turbine capital cost estimate of $415/kW for a January 1, 1982 plant on line date is reasonable.

54. Staff's 23-year plant economic life for the Edison combustion turbine estimate is reasonable and consistent with D.93887.

55. The escalation and discount rates used by staff for the Edison combustion turbine cost estimate are reasonable for the purposes of making that estimate.

56. Combustion turbine fuel inventory costs will escalate over the life of the plant and, for the purposes of the Edison combustion turbine cost estimate, 50% of the staff

oil escalation rate is a reasonable figure to use for fuel inventory escalation.

57. Edison's fixed administrative and general costs assumption is reasonable for purposes of calculating its combustion turbine cost estimate.

58. The increased system marginal operating costs resulting from the operation of the combustion turbine are more accurately reflected in avoided energy costs rather than avoided capacity costs.

59. SDG&E's 1982 combustion turbine capital cost estimate of $400/kW is reasonable for the purposes of QF pricing.

60. The SDG&E incremental cost of capital for the purposes of combustion turbine cost estimation is 15.5%.

61. Accurate combustion turbine costs for SDG&E include fixed administrative and general costs and staff's proposed escalation rates.

62. Staff and SDG&E are in agreement on fuel inventory costs, fixed O&M costs, and plant economic life assumptions for combustion turbine cost estimation. These assumptions are reasonable.

63. The staff's 1982 generic combustion turbine capital cost of $450/kW is reasonable for the purposes of PG&E's QF pricing.

64. The escalation rates used by staff for the Edison and SDG&E combustion turbine cost estimation are also accurate rates for PG&E's combustion turbine costs.

65. A 15.5% incremental cost of capital is a reasonable assumption for combustion turbine cost estimation for PG&E.

66. An accurate PG&E combustion turbine cost will include a fuel inventory cost commensurate with that found reasonable for Edison.

67. Plant economic life, fixed operation and maintenance costs, and fixed administrative and general cost assumptions adopted for combustion turbine cost estimation in D.93887 are reasonable for the purposes of the combustion turbine cost estimation used for PG&E's QF pricing.

68. PG&E proposes to adjust the combustion turbine shortage cost proxy used to calculate firm capacity prices to reflect year-to-year variations in reserve margins, using PG&E's Energy Reliability Index (ERI) methodology.

69. The ERI methodology is an innovative approach to measuring shortage costs.

70. The ERI methodology is conceptually flawed and biased downward because it only allows for downward, and not upward, adjustments in the annual shortage cost proxy.

71. A precise shortage cost methodology will allow for upward adjustments in the equilibrium shortage cost when loss of load probabilities are greater than the target level.

72. The ERI methodology is conceptually flawed and biased downward because it treats uncertain factors such as plant start up dates and plant maintenance requirements in a deterministic fashion in estimating future shortage costs and reserve needs.

73. The absence of a sensitivity analysis casts doubt on the validity of ERI results.

74. PG&E utilized several erroneous input assumptions when it used the ERI methodology to derive firm capacity prices.

75. The accurate estimation of future shortage costs requires, to the extent it is feasible, the simultaneous rather than sequential consideration of load management program, utility resources, and QF power.

76. PG&E's proposed revisions of its firm capacity price methodology to use different load management assump-

tions in the estimation of future ERI numbers and to include retroactive capacity payments if Helms pumped storage plant and Diablo Nuclear power plant startup dates are not realized do not remove the bias in its ERI-based capacity prices.

77. For the calculation of firm capacity prices, SDG&E has proposed a shortage cost methodology that adjusts the combustion turbine proxy for year-to-year variations in reserve margins.

78. The SDG&E method is conceptually flawed because it only allows for downward adjustments in the annual shortage cost proxy, not upward adjustments.

79. The SDG&E method is flawed because it does not allow year-to-year increases in shortage costs to be followed by decreases in those costs.

80. In calculating firm capacity prices using its shortage cost method, SDG&E did not adequately allow for utility plant start up date uncertainty and included an unrealistic assumption about the 1982 availability of the SONGS 2 nuclear plant.

81. SD&E did not adequately substantiate its shortage cost methodology nor its input assumptions.

82. Given the same input assumptions, calculation of annual combustion turbine cost using either a plant deferral concept or a real economic carrying charge concept should lead to the same result and either is reasonable.

83. For the calculation of firm capacity prices, Edison has proposed a shortage cost methodology that bases 1982-85 shortage costs primarily on wholesale emergency capacity prices in the California Power Pool Agreement and secondarily on the Edison-California Department of Water Resources Contract and the principles of interconnected operations for the Navajo and Four Corners Power projects.

84. The wholesale contracts that Edison utilizes for 1982-85 firm QF capacity prices are complex energy and capacity exchange agreements that involve shared reciprocal services.

85. The fact that the price of emergency capacity in the California Power Pool has not changed since 1967 despite inflation and narrow reserve margins makes more likely the possibility that this agreement is a mutually underpriced reciprocal transaction that is not an accurate proxy for avoided shortage costs.

86. Edison did not adequately substantiate its claim that the emergency capacity price is the marginal resource avoided by firm QF capacity purchases.

87. The shortage cost methodologies for firm capacity prices proposed by PG&E, SDG&E and Edison in these compliance hearings are unreasonable.

88. Further hearings are required before more refined shortage cost methods can be adopted.

89. The capital cost of the combustion turbine is a reasonable proxy for shortage costs to be used for as-available and firm capacity prices.

90. It is reasonable that energy prices in the as-available, firm and less than 100 kW offers should reflect as nearly as possible a utility's marginal variable operating costs.

91. The current standard offers create unnecessary risks for QFs that energy prices in some future period might not be derived from a utility's avoided costs.

92. It is reasonable for each contract to include language that energy prices will be derive from the utilities' marginal variable operating costs, as approved by the Commission, throughout the life of the project.

93. It is not feasible to include an energy price formula in standard price offers.

94. It is reasonable for interested parties to have the opportunity to review and comment on the utilities' calculation of energy prices.

95. The determination of energy rates derived from the utilities' marginal operating costs is in an evolutionary stage. Refinements will emerge over time.

96. It is reasonable for utilities to use average year estimates of incremental heat rates, as determined in rate cases, for the derivation of energy prices until the Commission approves a more refined methodology.

97. Actual incremental heat rate and fuel use data filed regularly would be useful for the evaluation of future period energy prices.

98. It is reasonable that the input of new plants which affect the incremental heat rates be determined in an ECAC proceeding.

99. Projected energy prices are less precise than retrospective calculations, but provide more pricing certainty for QFs.

100. Current natural gas prices more closely reflect marginal operating costs than do historical costs.

101. Oil may be burned to control inventory or for testing without being a marginal fuel.

102. Fuel used to warm-up facilities is not necessarily avoidable.

103. SDG&E avoids natural gas at the GN-5 rate, not the G-61 rate.

104. Fuel is not necessarily being avoided when used to maintain primary reserves.

105. No evidence now exists that transmission and distribution costs are avoided by QF purchases.

106. It is reasonable that variable operating and maintenance costs be included explicitly in the energy price derivations.

107. Insufficient data exists on line losses at this time. A reasonable assumption is that losses are equal to the line losses of utility plants, thus implying an aggregate line loss factor for QFs of 1.0, except for secondary line losses, which can reasonably be assumed to be the utility's marginal line losses.

108. Until sufficient evidence is presented by utilities for the identification and valuation of losses from remote sites, the loss for all QFs for energy can reasonably be established at 1.0.

109. Transformer losses need not be established if the meter is on the utility side of its transformer.

110. Limited evidence exists on the maximum probable number of hours utilities might invoke either for refusals to purchase or hydro spill conditions.

111. Restricting the number of hours for hydro spill or refusal to purchase is inconsistent with D.82-01-102 and D.82-04-071.

112. The option to pay QFs a higher capacity payment in return for up to 600 hours of curtailment during periods of economy energy purchases, while desirable, is an issue outside the scope of these compliance hearings.

113. Internal use of energy by QFs on simultaneous purchase and sale during curtailment would reduce demand and possibly exacerbate load problems the utility is seeking to solve through curtailment.

114. A levelized or price floor energy option is outside the scope of these proceedings.

Conclusions of Law

1. The Commission should continue to encourage the development of qualifying cogeneration and small power production facilities.

2. The standard offers of PG&E, Edison, and SDG&E should include capacity and energy payment provisions which comply with our decisions in OIR 2 and are reasonable.

3. The capacity and energy payment provision of the utilities' standard offers for as-available capacity and energy and firm capacity should be modified in keeping with the discussion and findings of this decision.

4. To promote the signing of standard offers by QFs, this order should be made effective today.

ORDER

IT IS ORDERED that:

1. Within 45 days of the effective date of this order, Pacific Gas and Electric Company (PG&E), Southern Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E shall file with the Commission's Docket Office an original and twelve copies of appropriate amendments to the standard offers included in Applications (A.) 82-03-26, 82-03-37, and 82-03-78 consistent with this decision and the ordering paragraphs contained herein.

2. Each utility's standard offer for firm capacity shall include the following requirements governing the performance standards to be applied to a qualifying facility (QF):

   a. Each standard offer shall include two payment options, one based on a QF's availability and the other based on a QF's energy production or output. PG&E's Standard Offer No. 2, Appendix C, Options 1 and 2, as modified in accordance with this order, shall serve as models for these payment options.

b. Dispatchability shall be defined to permit the utility to require only increases, not decreases, in a QF's operation. Dispatchability need not be limited to on and mid-peak periods and emergencies if the utility's payment option based on availability is similar to PG&E's Option 1.

c. Each payment option for firm capacity shall provide for payments in excess of a utility's capacity costs for QFs whose performance exceeds that of the utility's plants. To receive the higher payment, the QF's performance shall consistently exceed a peak period availability or capacity factor of 85%. For offers based on 100% of a utility's capacity costs, a QF shall only be required to maintain an availability or capacity factor of 80%. For a payment option based on a QF's availability which permits the higher payment, each utility shall include in the standard offer a method of determining whether and to what extent the QF has been dispatchable at a level of 85% or better.

d. Each utility's standard offer for firm capacity shall provide that hydroelectric QFs, which have their capacity ratings based on the five dry year average, shall not have their capacity terminated or derated when their failure to meet minimum performance requirements is due solely to the occurrence of a dry year which is drier than the five dry year average. During drier year conditions, a hydro QF shall be paid for the amount of capacity, if any, actually delivered to the utility. Capacity payments shall resume, at the contract price, when hydro conditions once again reach the level used to determine the capacity rating.

e. Each utility's standard offer for firm capacity shall include an allowance for scheduled maintenance which provides as follows: (1) Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. (2) A QF may accumulate unused maintenance hours on a year-to-year basis up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. (3) Reasonable advance notice to the utility of a scheduled outage shall be 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major overhauls), and six months for a major overhaul. (4) Major overhauls shall not be scheduled during the peak summer months. Reasonable efforts to schedule or reschedule routine maintenance outside the peak summer months shall also be made, but in no event shall outages for scheduled maintenance exceed 30 peak hours during the summer peak months. (5) No restrictions shall be imposed on the use of the scheduled maintenance allowance during the initial period of operation (i.e., the first six months). (6) Capacity payments shall apply during allowed outages for scheduled maintenance.

f. Each utility's payment options for firm capacity shall include provisions for the reduction of capacity payments in the event the QF fails to meet the minimum performance requirements. For both payment options, a probationary period not to exceed 15 months shall be adopted. For an availability option, like

PG&E's Option 1, if a QF fails to meet the minimum performance requirements, it shall continue to receive capacity payments for the amount of dispatchable capacity available during the probationary period. If after the expiration of this period, the QF has not demonstrated an ability to provide its full contract capacity to the utility, that capacity shall be derated and subsequent monthly payments limited to the new contract capacity. The amount by which the QF's capacity is reduced shall be subject to termination provisions. For an output option, like PG&E's Option 2, the QF shall earn capacity payments during the probationary period for the amount of capacity actually delivered. If the QF fails to deliver the full contract capacity during each of the following year's peak months, the contract capacity shall be derated to the monthly amount of capacity actually delivered during the peak months. The amount by which the QF's capacity is reduced shall be subject to termination provisions. Under both options, for capacity actually delivered during the probationary period, an allowance or credit for forced outages at the level otherwise specified in the utility's standard offer shall be included. The standard offer shall not include a provision for retroactive payments.

3. Edison's single payment option for firm capacity based on a QF's output and SDG&E's firm capacity payment Options 1 and 2 are not in compliance with D.82-01-103 and shall not be included in any standard offer for firm capacity.

4. The utilities' standard offers for firm capacity shall not include provisions for a QF to receive as-available ca-

pacity payments during the start-up period prior to the commencement of its firm capacity operations.

5. Each utility's standard offer for firm capacity shall include termination provisions which meet the following requirements:

a. Each utility shall provide for the reduction of capacity payments under the circumstances and in the manner provided in Ordering Paragraph 2(f) of this decision. Reductions in contract capacity shall not result in a complete termination of the contract but the amount by which the capacity is reduced shall be subject to termination provisions.

b. Each utility's standard offer for firm capacity shall require a QF terminating with prescribed notice to reimburse the utility for unearned capacity payments. Each of the utilities' methods for calculating this repayment, which are otherwise reasonable, shall include the requirement that interest be charged on the amount refunded. The interest charged shall be the published Federal Reserve Board three months' Prime Commercial Paper rate (plus 50 basis points for SDG&E).

c. The specific notice required for termination with notice shall vary depending on the amount of capacity being terminated. Tables similar to those in PG&E's and SDG&E's standard offers for firm capacity shall be included in each of the utilities' standard offers.

d. Each utility's standard offer for firm capacity shall require a QF terminating without prescribed notice to refund overpayments and to cover the utilities' replacement costs for the lost or reduced capacity. The offers shall in-

clude a liquidated damage clause calculating this additional payment for replacement costs similar to that prescribed in PG&E's Standard Offer No. 2, Appendix D (which reflects the actual notice given), with one modification. The adopted formula shall reflect the time needed, as indicated by the notice table, to replace the lost capacity. The utilities' calculation of their damages may refer to future capacity prices.

e. The utilities' termination provisions shall not require a QF to provide evidence of its ability to make potential termination payments.

f. Each utility's standard offer for firm capacity shall include examples of the operation of its termination provisions.

g. The requirements of D.82-01-103 with respect to conversions from the simultaneous purchase and sale of energy to the sale of surplus only shall be reflected in a utility's standard offer for firm capacity. Termination provisions shall only apply to the amount by which the contract capacity is reduced as a result of the conversion.

6. A standard offer for as-available capacity shall not include any notice requirement for termination.

7. The utilities shall file, along with the amendments to the standard offers ordered in Ordering Paragraph 1 above, firm and as-available capacity prices based on 100% of the capital costs of the combustion turbine, using the combustion turbine cost estimates adopted in this decision.

8. Edison's combustion turbine capital costs shall be based on the following assumptions:

a. A $415/kW 1982 combustion turbine cost.

b. Escalation and discount rates proposed by staff for Edison in this proceeding.

d. Fuel inventory costs proposed by staff with the exception that staff's inventory escalation rate shall be reduced by 50%.

e. Administrative and general costs which, on a levelized basis, shall be equivalent to 1% of the combustion turbine capital cost.

f. No differential fuel credit.

g. Fixed operation and maintenance costs to which staff and Edison have agreed in this proceeding.

9. SDG&E's combustion turbine capital cost shall be based on the following assumptions:

a. A $400/kW 1982 combustion turbine capital cost.

b. A 15.5% incremental cost of capital.

c. Fixed administrative and general costs commensurate with those adopted for Edison.

d. Fuel inventory costs, fixed operations and maintenance costs and plant economic life to which staff and SDG&E have agreed in this proceeding.

e. Staff's proposed escalation rates for SDG&E.

10. PG&E's combustion turbine capital cost shall be based on the following assumptions:

a. A $450/kW 1982 combustion turbine cost.

b. Escalation rates adopted for Edison and SDG&E.

c. A 15% incremental cost of capital.

d. Fuel inventory costs commensurate with those adopted for Edison.

e. Plant economic life, fixed operation and maintenance costs; and fixed administrative and general costs adopted for combustion turbine cost estimation in D.92887.

11. More refined shortage cost methodologies such as those proposed by the utilities in this proceeding for firm capacity payments shall be examined for possible application to QF pricing in SDG&E's and PG&E's current general rate cases and hearings on Edison's five-year energy price offer (A.82-04-46). Any revision in capacity prices that is adopted by the Commission because of this examination shall only apply prospectively to QFs that sign after the date of the orders in those proceedings.

12. Each utility's standard offer for energy shall reflect the following:

a. Each utility shall modify its as-available and firm capacity contracts, and its contract for QFs less than 100 kW to state that energy prices will be derived from the utilities' full avoided operating costs, as approved by the Commission, throughout the life of the contract.

b. Utilities shall file with the Commission's Docket Office beginning six months from the effective date of this order an original and twelve copies of their actual average incremental heat rates and fuel use quarterly, in the case of PG&E and Edison, and three times a year, in the case of SDG&E. The relevant models shall be modified to make whatever changes are required.

c. Utilities shall use the average year incremental heat rates, as determined in the most recent

rate case, for the derivation of energy prices until the Commission approves refinements.

d. The utilities shall file with the Commission's Docket Office by September 30, 1983 an original and twelve copies of a plan for estimating actual year incremental heat rates prospectively.

e. Utilities shall propose incremental heat rate revision in Energy Cost Adjustment Clause (ECAC) proceedings after new power plants come on line.

f. PG&E and Edison shall file with the Commission's Docket Office an original and twelve copies of prospective energy prices quarterly, 30 days prior to the date the prices take effect. Included with the filing shall be a clear, comprehensive description of how the prices were derived, in order to permit staff and interested parties to comment on them. Gas prices used for avoided energy costs shall be tentative and finalized using the price in effect on the effective date of the price change.

g. Absent Commission action, these price offers shall take effect on the scheduled effective date.

h. SDG&E shall file its energy prices three times a year in parallel with ECAC proceedings. Unless the Commission orders revisions, these prices shall become affective on the scheduled effective date. SDG&E shall provide a clear, comprehensive description of how the prices were derived.

i. SDG&E shall use the GN-5 natural gas rate for the determination of its energy prices.

j. Until revised line loss adjustment factors are approved by the Commission, PG&E's, Edison's, and SDG&E's transmission and primary distribution loss adjustments for energy shall be set at 1.0. Marginal line losses shall be used for PG&E's, SDG&E's, and Edison's secondary distribution loss adjustment for energy.

k. PG&E shall complete a revised line loss study in cooperation with staff and QF representatives and file an original and twelve copies with the Commission's Docket Office within six months of the effective date of this order. The study shall include a methodology for identifying and determining losses from remote sites.

1. SDG&E and Edison shall complete line loss simulation studies in cooperation with staff and QF representatives within two years and file an original and twelve copies of the results with the Commission's Docket Office.

m. Utilities shall include variable operating and maintenance costs in energy prices.

n. Utilities shall permit meters to be fixed on the utility side of a transformer. Transformer loss provisions shall be removed from standard contracts if a QF decides to put the meters on the utility side.

o. Offers to include 600 hours of curtailment in exchange for a higher energy rate the rest of the time, to levelize energy payments, or to adopt floors shall be viewed as nonstandard offers at this time, and outside the scope of these proceedings. Any such provisions shall not be included in standard offers.

p. Utilities shall delete any language which would reduce capacity payments for QFs during periods when they fail to perform under capacity contracts due to the utility refusing to purchase from the QF.

q. PG&E, Edison, and SDG&E shall file with the Commission's Docket Office within three months of the effective date of this order an original and twelve copies of studies estimating the average and maximum probable application of refusal to purchase and hydro spill provisions in future years.

13. The petitions for modification filed by CMA and Imotek, Inc. in OIR 2 are dismissed.

This order is effective today.

Dated December 30, 1982, at San Francisco, California.

I will file a concurring opinion.

/s/ LEONARD M. GRIMES, JR.
Commissioner

RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
Commissioners

Commissioner Priscilla C. Grew, being necessarily absent, did not participate.

APPENDIX A
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LIST OF APPEARANCES

Applicants: Daniel E. Gibson, *David L. Ludvigson, Jo Shaffer*, and Ken D. Oleson, Attorneys at Law, for Pacific Gas and Electric Company; *Margaret A. Glodowski*, Attorney at Law, for Sierra Pacific Power Company; *Thomas F. Mulvaney*, Attorney at Law, for CP National Corporation; Stoel, Rives, Boley, Fraser and Wyse, by *Thomas H. Nelson*, Attorney at Law, for Pacific Power & Light Company; Margaret Sullivan and *Wayne P. Sakarias*, Attorneys at Law, for San Diego Gas & Electric Company; and *Eugene Wagner*, Richard K. Durant, Clyde E. Hirschfeld, Carol B. Henningson, and Frank J. Cooley, Attorneys at Law, for Southern California Edison Company.

Interested Parties: Chickering & Gregory, by *C. Hayden Ames*, Attorney at Law, and *C. M. Laffoon*, for Geothermal Generation, Inc.; *Robert Burt*, for California Manufacturers Association; *James J. Cherry*, Attorney at Law, for Independent Power Producers Association; *Janet M. Curry*, for Department of Water Resources; *Robert Danziger*, Attorney at Law, for Sunlan Energy Corporation; *Michel Peter Florio* and Robert Spertus, Attorneys at Law, and Sylvia Siegel, for Toward Utility Rate Normalization (TURN); *James Helmich*, for Helmich Engineering; *Mark Henwood*, for Henwood Associates, Inc.; *Steven F. Hirsch*, Attorney at Law, and Laura B. King, for Natural Resources Defense Council, Inc.; Catherine Johnson, Gregg Wheatland, Kathy Weinheimer, and *Daniel Meek*, Attorneys at Law, for California Energy Commission; Morrison & Foerster, by Charles R. Farrar, Jr. and *Alan Cope Johnson*, Attorneys at Law, for Great Western Malting Company, Kerr-McGee Chemical Company, and Kimberly-Clark Corporation; *Jane S.*

Kumin, Attorney at Law, for Natomas Company and Thermal Power company; *John C. Lakeland*, for Mass-Production Systems; *W. J. Lawrence*, for Western Energy Associates; *Philip R. Mann*, Attorney at Law, for CMA Cogeneration Group and P. R. Mann & Associates; Graham & James, by Boris H. Lakusta, *David J. Marchant*, Thomas J. MacBride, and James B. Henly, Attorneys at Law, for Graham & James; *Wayne L. Meek*, for Simpson Paper Company; *Michael McQueen*, Attorney at Law, for Union Oil Company of California; Hanna & Morton, by *R. Lee Roberts*, Attorney at Law, for Hanna & Morton; *Donald G. Salow*, for Stone & Webster Management Consultants, Inc.; *Robert W. Schempp*, for Metropolitan Water District of Southern California; Petty, Andrews, Tufts & Jackson, by *Allen J. Thompson*, Attorney at Law, for California Independent Energy Producers; *Randall Tinkerman*, for Transition Energy Projects Institute; *Harry Winters* and *David A. Dorinson*, Attorney at Law, for University of California; *Robert M. Loch*, Attorney at Law, for Southern California Gas Company; *Donna M. Bronski* and Don Dier, for Department of General Services; *Gordon E. Davis*, William H. Booth and Richard C. Harper, Attorneys at Law, for Brobeck, Phleger & Harrison; Grattan, Gersick & Karp, by *John P. Grattan*, Attorney at Law, and *John V. Hilberg*, for Calcogen, Inc.; *Ken Haas*, Attorney at Law, for Windfarms, Ltd.; *Janice G. Hamrin*, for Independent Energy Producers Association; *Neil K. Holbrook*, for California Wind Energy Association; *Jeffrey E. Jackson*, and Thomas D. Clarke, Attorneys at Law, for Central Plants, Inc. and Pacific Hydropower Company; *Peter S. Reis*, Attorney at Law, for Texaco, Inc.; *Leonard L. Snaider*, Attorney at Law, and Robert Laughead, P.E., for the City and County of San Francisco; *Mark Farman*, for Resource Mangement International; *Carl*

E. Salas, for O'Brien Associates, Inc; *Jasper Williams*, Attorney at Law, and *William Swanson*, for Stanford University; *Jerry R. Bloom*, Attorney at Law, for Kimberly-Clark Corporation; Downey, Brand, Seymour & Rohwer, by *Philip A. Stohr*, Attorney at Law, for Federal Paper Board; Sutherland, Asbill and Brennan; Edward J. Grenier, Jr., Esq.; and Earle H. O'Donnell, Esq.; Hanna & Morton, by *R. Lee Roberts*, Attorney at Law, and William C. Prentice, for Ultrasystems, Inc.; *Ernest Lampert*, for United Energy Corporation; Brobeck, Phleger & Harrison, by Gordon E. David, William H. Booth, and *Richard C. Harper*, Attorneys at Law, for Imotek, Inc.; Terry Trumbull and *Robert F. Conheim*, Attorneys at Law, for the California Waste Management Board; *Peter S. Merrill*, for Cogenerating Power Company; *William S. Shaffran*, Deputy City Attorney, for John W. Witt, City Attorney, for the City of San Diego; *John Donald Eppick*, for County Sanitation Districts of Los Angeles County; Gordon E. Davis and *William H. Booth*, Attorneys at Law, for U.S. Windpower, Inc.; and *Matthew V. Brady*, Attorney at Law, *Doug Knight*, and *Vincent Schwent*, for themselves.

Commission Staff: *Brian T. Cragg* and *Lynn T. Carew*, Attorneys at Law, and *John Quinley*.

COMMISSIONER LEONARD M. GRIMES, JR., Concurring:

I concur in today's decision and write separately to express my views on projects which are designed to convert solid waste into electrical energy. I believe that these projects are of special value since they address the problem of public waste disposal in addition to providing all the benefits associated with alternative energy development.

Despite some efforts at recycling, we are still a throw-away society. Thousands of tons of waste are generated in our cities each day to the point where garbage may be the principal product of our urban centers. As the public officials responsible for "managing" our garbage are well aware, the economic and environmental costs of municipal waste are substantial.

Spurred on by landfills which are full and near-full and the difficulty of securing additional disposal capacity, a number of California cities have planned waste-to-energy systems ranging from 5 to 38 MW. These projects are among the most capital-intensive endeavors undertaken by local governments. Their success, in part will depend on the terms and conditions under which the cities will be paid for the power they produce.

While today's decision on the short term standard offers does not address waste-to-energy projects specifically, the decision should be of some assistance to these projects. The firm capacity output option may be attractive to waste-to-energy producers. The long term offer which is being developed may also be a useful option. Should non-standard contracts be necessary, I urge PG&E, SDG&E, and Edison to make every effort to sign reasonable contracts.

In my opinion, the risk to electric ratepayers from waste-to-energy projects is mitigated by the fact that such projects will be developed and operated by public agencies which are clearly interested in the long term operation of

their facilities. Also, attempts to shield electric ratepayers may ultimately prove to be futile. Risks not absorbed by electric ratepayers are simply shifted to garbage ratepayers. In many cases, they will be the same people responsible for generating the garbage in the first place.

/s/ Leonard M. Grimes, Jr.
LEONARD M. GRIMES, JR., COMMISSIONER

San Francisco, California
January 5, 1983

Decision 83-05-038 May 4, 1983

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Second Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-04-44 (Filed April 21, 1982)

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY for an Order by the California Public Utilities Commission Directing Edison to Purchase Power from Qualifying Facilities Based on a Standard Offer for Firm Capacity and Energy Based on Long-Run Marginal Costs (OIR-2).	Application 82-04-46 (Filed April 21, 1982)

In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for an Order by the California Public Utilities Commission Directing SDG&E to Purchase Power from Qualifying Facilities Based on Standard Offers and to Make Certain Changes or Additions to its Tariff Affecting Purchases from Qualifying Facilities.	Application 82-04-46 (Filed April 21, 1982)

INTERIM OPINION ON PROCEDURAL GUIDELINES

Introduction

The purpose of this decision is to establish a procedure to help resolve issues surrounding the "long-term resource plan based offer" (Standard Offer No. 5) ordered by the Commission in Decision (D.) 82-01-103, Order Instituting Rulemaking (OIR) 2, (January 21, 1982).

D.82-01-103 established comprehensive guidelines for sales of electricity from small power producers to utilities. The utilities were ordered to file five standard offers, each with different terms and conditions. The first four offers were all derived from short-run avoided cost methodologies that are conceptionally well understood, even though many difficult details needed to be worked out in compliance hearings.

The conceptual approach for development of the offer was not established for the long-run resource plan offer, and D.82-01-103 ordered utilities to make proposals for our review. After reviewing those offers, it became clear that evidentiary compliance hearings would lead to pro-

tracted conceptual cross-examination on how to pay small power producers entering long-term contracts for their value in deferring new utility capacity. Rather than starting with the utility proposals, we decided it would be preferable to define the alternatives, present some tentative proposals, and receive comments from parties. With this approach, parties' general positions could be better understood, and we hoped to establish a framework before going into detailed compliance hearings on specific utility offers filed within that framework.

So, we issued on November 18, 1982 a *Report and Request for Comments* (Report) which presented issues relating to Standard Offer No. 5 and tentatively proposed a framework for such an offer. The Report concluded that an interim offer should be based on a five-year forecast of utility projected short-run marginal costs, followed by prices in future years based on the energy and capacity costs of a new coal plant. The Report also proposed that payments escalate over the life of the contract to avoid complex termination requirements and that the small power producer should be given flexibility about the output commitment it will take for future years. We asked parties to comment.

Responses by Parties to Commission Report

By January 31, 1983 the Commission received comments on the Report from *18* interested parties addressing both substantive and procedural issues. The comments were uniformly helpful. The comments included constructive criticisms of the Report and imaginative alternative frameworks for a long-run offer. The Commission was presented good information on how to achieve a workable and useful long-term offer.

Most importantly, the comments indicated a broad consensus about the need to achieve the underlying purpose of the Standard Offer No. 5 which is to provide *greater price certainty* and to value the small power producers'

facilities consistently with utility resources. Pacific Gas and electric company (PG&E), for example, while disagreeing with much in the Commission's Report, strongly endorsed the Report's purpose:

> "It has become apparent that the currently available standard offers do not meet the needs of all QFs. One of the major reasons for this is the high degree of future price uncertainty in these offers which adversely affects the ability of some projects to obtain financing. . . . A well designed standard offer, which mitigates the uncertainty, is consistent with avoided cost principles, and balances ratepayer and QF risk would also be desirable." (PG&E comments, page 1.)

PG&E offers a new proposal for a framework to provide greater pricing certainty for small power producers. Similarly, Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) express general accord with the purposes of the Report and make new proposals for a standard offer framework.

Parties representing small power producers also agree that a greater pricing certainty is necessary. Many point out that different facilities have different needs and possibly more than one long-term price offer should be available.

In addition to providing useful substantive information, the comments also suggest procedures for resolving this matter. There was significant difference of opinion among parties on procedure.

In our Report, we tentatively concluded "that resolution of *conceptual* and *policy* issues on what methodology is to be selected for the long-term offer does not require factual evidence, but can instead be more effectively decided through written comments and possibly oral presentations." (Commission Report, page 6.) We envisioned the

conceptual and policy issues being resolved through a rulemaking-type procedure, while the details of an actual offer would be resolved in subsequent compliance hearings.

PG&E and SDG&E strongly disagree with this procedure. They argue that evidentiary hearings are necessary before the conceptual issues in the standard offer can be resolved. PG&E argues that fairness and due process require that hearings be held. "[I]t would be highly undesirable to resolve these very complex issues without the benefit of evidentiary hearings." SDG&E expresses similar concerns, arguing that the proposed format by the Commission would lead to lengthy compliance hearings and uncertainty about the details of any final order.

SCE also suggests that evidentiary hearings are necessary:

> "Edison believes that these hearings can be handled expeditiously, and without undue delay, if the scope of such hearings is clearly defined. While we certainly agree that the public interest is not served by delay, neither is it served by an incomplete examination of the complex issues surrounding this topic, possibly resulting in the selection of a costing methodology that inaccurately values QF power to utilities and their ratepayers. Edison suggests that, upon receipt and examination of the comments submitted by the various utilities and interested parties, the Commission should submit a 'summary report' which delineates both the various proposals presented and the issues to be examined in an evidentiary hearing."

Many of the other parties commented on procedure. Pacific Energy Resources (Pacific Energy) agreed to hearings. While stating that the Commission report provides a helpful framework, it argues that:

> "[I]ssues raised in this report can be only fully explored by means of hearings before the Commission. At such time each interested party and each utility can present alternative methods of implementing the proposals outlined by the Commission in its report and can present alternative proposals for consideration." (Comments of Pacific Energy, page 10.)

The hearings contemplated by Pacific Energy appear to involve direct presentations to the Commission rather than substantial cross-examination.

Occidental Geothermal, Inc. suggests that "further cooperative exchange of ideas is necessary before QFs can formulate any comprehensive proposal." (Comments of Occidental Geothermal, Inc., page 6.) To that end, it proposes a sequence of workshops, evidentiary hearings on issues relating to project risks, briefs, a decision to order utilities to file an offer, followed by compliance hearings and a decision. Ultrasystems Incorporated also suggests evidentiary hearings on risk-related issues.

California Manufacturers Association basically supports our proposed procedure. It suggests workshops, briefs, followed by a Commission decision, followed by compliance hearings on utility filings. California Independent Energy Producers also supports our proposal.

Natural Resources Defense Council agreed that evidentiary hearings are not necessary, but suggested parties should have the opportunity to comment on other parties' comments. Similarly, the California Energy Commission suggests another round of comments after this Commission issues a more detailed rule.

1. Procedural Course and Guidelines

The decision on how to proceed with these consolidated matters is important. We are aware that some QFs are anxious to see this standard offer resolved soon in order

to decide whether to begin projects. Delay on completing this offer could arrest QF development. On the other hand, it is also important to explore these issues to assure that ratepayers' interests are protected.

There are two major alternatives developed by parties. One proposed by utilities would be to hold evidentiary hearings on all of these issues, followed by an order, followed by compliance hearings on utilities' offers. The second general proposal would be the receipt of further written and oral comments, followed by compliance hearings.

Either approach would be overly time consuming and would not necessarily serve the interests of parties. The comments of parties convince us that a long-term standard offer is highly complex, involving avoided cost methodology, performance requirements, and termination penalties. The issues will not be quickly resolved under either procedure. Because of the complexity, we also are not certain that a Commission-ordered standard offer will best meet the needs of parties. It is evident that there are many possible standard offers which could be developed that are consistent with avoided cost pricing principles.

We have decided, therefore, to use a different procedure to resolve this matter before holding any formal evidentiary hearings. We have decided to hold a negotiating conference to give parties an opportunity to work together toward a methodology for an interim long-term standard offer[s]. We noted earlier that there is widespread consensus among parties on the immediate need for the long-term standard offer to provide greater pricing certainty and to reflect the value of QFs in deferring new utility resources. While there are many ideas on how to translate this concept into an offer, we think with the mutual objective of a timely decision in mind, parties can reach an accord.

The negotiating conference, to be held before any formal hearings on the long-term offers, is intended to achieve three things: (i) establish an offer[s] which can be filed by utilities at least on an interim basis which will be supported by the parties; (2) an agreement on a proposal clearly identifying issues, if any, which require further proceedings; and (3) a better understanding by all parties of each other's positions on this complex matter. This, in turn, will lead to sharper definition of issues for any formal hearings in the future. The Commission, of course, will review and approve any interim offer, and address any proposals for additional proceedings. However, with substantial agreement among parties, we expect to be able to act more expeditiously.

The negotiating conference is a new procedure for the Commission. It should take place in a spirit of cooperation, not of adversarial posturing. Parties should come prepared for an intensive period of education, negotiation, and problem solving. Parties will all benefit by reaching an accord because an interim offer may then be quickly put in place.

We expect the negotiating conference to reach substantial agreement within one month after it commences in the middle of May. We will make as much time available during that month as is necessary for parties to work out an agreement. A tentative schedule for the conference will be presented by the administrative law judge (ALJ) on the first day of the conference. Parties will have an opportunity to review and discuss it. We expect the schedule to permit a thorough presentation of positions on the major issues by parties, followed by analysis, followed by negotiations to settle on an offer. The dynamics of the conference will, of course, depend upon the nature of the issues that need to be discussed.

The negotiating conference will being on May 23, 1983, and will last not longer than four weeks, with regularly scheduled meetings. Parties should send representatives

who can commit extensive time to this process and who can present positions and negotiate. We encourage QFs with similar interests to join and work together. We also encourage parties not only to send technical staff, but also be represented by those who can negotiate and make decisions. The staff will be represented by the Director of the Utilities Division, who will be supported by technical staff and staff counsel.

When the negotiating conference ends, the ALJ will issue a ruling which sets the time in which the three applicant utilities shall amend their applications with new standard offers. After a reasonable time for all parties to review and evaluate the amended standard offers, we will schedule a prehearing conference to evaluate the need for evidentiary hearings and, if they are required, their scope.

In order to encourage open participation at the negotiating conference, we will order that Rule 50 of our Rules of Practice and Procedure shall apply.[1] That will encourage a free and candid exchange of information, ideas, and alternatives.

2. Issues for Resolution

The comments in response to our Report provided many useful suggestions on defining a long-term contract and highlighted the issues that need to be settled. Two broad issues arise. First, what costs are avoided by long-term QF contracts? Second, a related, and workable pricing mechanism, with appropriate contract terms and conditions, must be established to pay the QFs for their contribution of providing electricity to avoid those costs. The nature of these payments may vary depending upon the conditions of operation agreed upon by QFs. Generally,

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[1] Rule 50 provides as follows: "(Rule 50) Facts Disclosed Privileged. Facts disclosed in prehearing conferences are privileged. Except by agreement, they shall not be used against participating parties, before the Commission or elsewhere, unless proved by evidence other than that employed in disclosing such facts."

the utilities devoted more attention to the first issue of costing, while QFs generally devoted more to the latter issue of pricing.

a. Costing Methodologies

The utilities generally support use of projected shortrun avoided costs (i.e., marginal running costs plus shortage value) for use in defining a long-run offer. Utilities assert that the criteria for determining whether a utility would add a new resource depends on whether the capital and operating costs of the proposed resource is less than the projected short-run avoided cost. Resources are added until the two are equal according to the rule of economic dispatch.

We agree that methodologies using projected short-run avoided costs and using the costs of new resources should produce the same results in theory. However, the problem is translating projected costs into QF prices. The utilities contend that the shortrun methodology can be used. The Commission's Report found that a coal plant would be a simpler proxy. Other parties expressed mixed views on the issue.

We expect this issue to be developed fully in the negotiating conference. Parties should have the opportunity to demonstrate clearly how to derive avoided cost numbers from their marginal cost methodology. A major criteria for consideration will be workability as well as theoretical validity. We are looking for *results*. We expect the negotiating conference to develop a consensus methodology that fairly reflects the long-term value of QF power that can be readily implemented through pricing.

b. Pricing

It is apparent from the comments that developing an avoid cost estimate represents only part of the problem of developing a standard offer. Equally difficult is trans-

lating those costs into a contract with prices, terms, and conditions.

QFs have different views on what the contracts should be like. Some QF representatives, particularly those with cogeneration facilities, are interested in fixing incremental heat rates in a contract, but not fixing total fuel prices, since a cogenerator's fuel price may fluctuate with the rates of serving gas utilities. Others would like more pricing certainty, including in some cases, levelized payments. Another area of difference involves performance requirements. Some QFs can produce reliably based on very stringent performance standards, others produce intermittently and seek a more flexible standard.

These differences explain why QFs want an array of standard offers; however, we must caution the parties that trying to devise a number of standard offers to accommodate all QF situations - and which do not result in favoring some QF technologies over others - will result in tremendous complexity and, of course, attendant delay.

We welcome some variety of long-term offer options, but we stress that all variations must be consistent with avoided cost principles. If levelized payments are proposed, for all or part of the contract term, we expect corresponding proposals to mitigate potential loss to the ratepayer resulting from nonperformance or overpayment.

c. Resolution of Issues Resulting From the Negotiating Conference

We expect that most of the issues can be resolved in the negotiating conference to permit an agreement on an offer that utilities should file on an interim basis. The agreement should include both a conceptual framework and a means of driving specific prices. We do not expect that parties will waive their rights to further proceedings in this matter. The long-term offer methodology is evolving, and it may be useful to further analyze the question later.

Therefore, in addition to a standard long-term offer, we solicit a consensus from parties on a procedure for further analysis of the long-term offers.

All parties should come to the negotiating conference with the list of issues which they see needing to be resolved, and should be prepared with proposals for resolution of issues. Staff will prepare and submit a comprehensive listing based on the comments for review already filed by parties. We expect the proposals to be offered with a spirit of compromise. Everyone will have the opportunity to present their proposals at the negotiating conference and make suggestions for improvements of other proposals.

INTERIM ORDER

IT IS ORDERED that:

1. A negotiating conference to be presided over by ALJ Alderson shall be held on May 23, 1983, at 9:30 a.m. at Hastings College of the Law, 198 McAllister Street, Room K, San Francisco. This conference shall continue over a four-week period, with the schedule to be set by the ALJ. It will not be reported by the Commission's Reporter, and the use of material disclosed during the conference will be governed by Rule 50 of the Commission's Rules of Practice and Procedure.

2. After the negotiating conference ends, the ALJ shall issue a ruling providing a time limit within which the applicants shall amend their applications with revised standard offers. Thereafter, a prehearing conference shall be scheduled to assess the need for hearings and define their scope.

3. This order shall also be served on the applicants and the parties served with D.82-12-120 in Application 82-03-26 et al.

This order is effective today.

Dated May 4, 1983, at San Francisco, California.

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
Commissioners

I abstain
/s/ PRISCILLA C. GREW
Commissioner

BEFORE THE PUBLIC UTILITIES COMMISSION

STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority, among other things, to increase its rates and charges for electric and gas service. (Electric and Gas) U 39 M	Application No. 82-12-48

PETITION OF PACIFIC GAS AND ELECTRIC COMPANY FOR MODIFICATION OF DECISION NO. 83-12-068

Pursuant to Rule 43 of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company ("PGandE" or "Company") hereby petitions for modification of Decision No. 83-12-068 for the limited purpose of extending the capacity price table for Standard Offer No. 2.

Capacity prices for Standard Offers No. 2 and 4 were established in PGandE's 1984 General Rate Case in Table IV-4 at page 349 of Decision No. 83-12-068. Three clerical errors in this table were corrected by the Commission in Decision No. 84-05-101. Table IV-4 covered contracts with operating dates through 1988.

This table now needs to be updated. A QF signing a Standard Offer No. 2 has five years to become operational. Therefore, projects signing Standard Offer No. 2 in 1985 may come on line as late as 1990, although no capacity prices for 1990 were ever adopted by the Commission. Similarly, projects signing in 1986 may come on line in 1991. Therefore, to accommodate QFs who sign Standard

Offer No. 2 prior to January 1, 1987 (the effective date of PGandE's 1987 General Rate Case Decision), the Commission should extend the Firm Capacity Price Schedule to 1991.

Accordingly, PGandE requests that the Commission extend the firm capacity price table to include 1989-1991. The proposed prices which would be paid are shown in Attachment A.

The figures in Attachment A are based on the same assumptions used to develop Table IV-4 in Decision No. 83-12-068. They do not reflect any of the proposals which PGandE may include in its 1987 General Rate Case to be filed in December, 1985.

PGandE believes this Petition requests that the Commission merely perform a ministerial act. However, since capacity prices will be an issue in the 1987 General Rate Case, PGandE proposes that if this Petition is opposed and the Commission believes hearings are necessary, that the matter be deferred until the hearings in the 1987 General Rate Case. Since the basis for Attachment A is information developed over three years ago, there is no point in having hearings on such stale data.

Accordingly, PGandE requests that the Commission modify Decision No. 83-12-068 to include the capacity prices for projects commencing operation in 1989-1991 as shown in Attachment A.

Respectfully submitted,

HOWARD V. GOLUB
ROGER J. PETERS
MICHALE S. HINDUS

By _____
Michael S. Hindus

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 4, 1985

ATTACHMENT A

Firm Capacity Price Schedule

(Levelized $/KW-year)

Actual Operation Date (Year)	1	2	3	4	5	6	7	8	9
1989	115	119	123	127	130	134	138	141	144
1990	124	128	132	136	140	144	147	151	155
1991	132	137	141	145	150	154	158	162	166

10	11	12	13	14	15	20	25	30
148	151	154	157	160	163	176	187	195
158	162	165	169	172	175	189	200	209
169	173	177	180	180	184	202	214	223

Note: Based on the assumptions underlying Table IV-A in Decision 83-12-068.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Second Applications of PACIFIC GAS AND ELECTRIC COMPANY for approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Instituting Rulemaking No. 2.	Consolidated Application No. 82-04-044 et al. and Application No. 82-03-026, et al. (Filed December 2, 1986)

And Related Matters.

RESPONSE OF FOSTER WHEELER POWER SYSTEMS, INC. TO PACIFIC GAS AND ELECTRIC COMPANY'S APPLICATION FOR REHEARING OF DECISION 86-10-038

I. INTRODUCTION

On November 17, 1986 Pacific Gas and Electric Company ("PG&E") applied to this Commission for a rehearing of the Commission's Decision 86-10-038, issued October 16, 1986 (the "Decision"). In its application, PG&E repeatedly asserts that the firm capacity price table ("Table E-2") in the interim Standard Offer No. 4 contract (the "SO4") ends in 1987. PG&E argues from this assertion that if a seller under an SO4 fails to establish a firm capacity availability date ("FCAD") for its qualifying facility ("QF") by 1987, it forfeits all rights to receive any of the Table E-2 firm capacity prices, and must then negotiate new prices with PG&E. PG&E therefore contends that the Commission erred in extending the Table E-2 prices through 1990 in the Decision.

Foster Wheeler Power Systems, Inc. appears in this proceeding on behalf of its wholly-owned subsidiary, Foster Wheeler Martinez, Inc. ("FWM"), which will own and operate a 90 MW cogeneration facility (the "Facility") that is currently being constructed at the Tosco Corporation's ("Tosco") Avon Refinery in Martinez, California. Power from the Facility will be sold to PG&E pursuant to an executed SO4 (the "FWM SO4"). At FWM's request, the Table E-2 in the FWM SO4 was extended by PG&E through *1988,* using escalated prices based on the firm capacity price methodology previously adopted by the Commission. The actions of PG&E in extending this Table E-2 directly contradict its arguments in its Application for Rehearing, and demonstrate that those arguments are simply an attempt by PG&E to evade its obligations under executed SO4's.

FWM also filed an Application for Rehearing of the Decision on November 17, 1986. In that application, FWM argued that the Decision had erred in one limited respect, in that it changed the basis for calculating firm capacity payments under the SO4 from the FCAD to the Scheduled Operation Date ("SOD")*. FWM explained in its Application for Rehearing why this retroactive amendment of SO4 must be remedied.

In this Response, FWM wishes to point out: (i) that *all* parties to these proceedings agree that under the terms of the SO4, the FCAD determines firm capacity prices under Table E-2; and (ii) that PG&E's prior actions in

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*Under the SO4, the FCAD is the date on which a QF is *actually* ready to begin delivery of firm capacity. The FCAD therefore by definition cannot be specified in advance. The SOD is the *estimated* date of initial energy deliveries from a QF. The SOD is only a non-binding, estimated date of operation and may be changed at any time by a seller. *See* Application for Rehearing of Decision 86-10-038 by Foster Wheeler Power Systems, Inc. (on behalf of FWM) filed November 17, 1986 at 5-7 (hereinafter "FWM Application").

extending the Table E-2 in the FWM SO4 through 1988 undercut its arguments in its Application for Rehearing.

II. ALL PARTIES TO THESE PROCEEDINGS UNDERSTAND THAT THE FCAD DETERMINES FIRM CAPACITY PRICES UNDER THE SO4.

In its Application for Rehearing, FWM explained that the SO4 plainly states that firm capacity prices under Table E-2 are calculated on the basis of the FCAD, with the term "Firm Capacity Availability Date" displayed prominently in every Table E-2. FWM also pointed out that PG&E has repeatedly stressed these same clear terms in its previous filings in these proceedings.*

In its Application for Rehearing, PG&E again reaffirms this common understanding. PG&E explains that "Table E-2 provides prices based on avoided costs calculated at the time the obligation was incurred for firm capacity availability dates. . . ."** Other parties submitting filings to these proceedings make the same obvious point.***

All parties also recognize that the Decision would apparently alter these plain contract terms, and substitute the SOD for the FCAD in firm capacity price calculations,*

**See* FWM Application at 8-9.

***Application for Rehearing of Decision 86-10-038 by Pacific Gas and Electric Company, filed November 17, 1986 at 15 (hereinafter the "PG&E Application"). *See also id.* at 8, 11.

****See* Application of Independent Energy Producers Association for Rehearing of Decision 86-10-038, filed November 17, 1986 at 2-3; Application by Ultrapower, Inc. for Rehearing of Decision No. 86-10-038, filed November 17, 1986 at 4-6; Application for Expedited Limited Rehearing of Decision 86-10-038, filed by Basic American Foods on November 17, 1986 at 3-5.

**See e.g.*, PG&E Application at 1-2. PG&E characterizes the SOD as the date by which sellers "promised" to come on-line. As explained in the FWM Application, the SOD is only a non-binding estimate of a facility's on-line date, which may be changed at any time by a seller. No seller in any SO4 ever covenanted to be on-line by the SOD.

despite the fact that no party had ever argued for such a retroactive amendment of SO4 by the Commission. Not even PG&E attempts to defend this substantive amendment of SO4, even though the amendment would strip some QFs of the firm capacity prices specified in their contracts.** PG&E, like the other parties to this proceeding, is contesting the propriety of extending the price terms of Table E-2, not of *amending* the method for determining the *existing* firm capacity prices under the Table. For the reasons set forth in FWM's Application for Rehearing, the Commission must re-affirm that the FCAD is the basis for calculating firm capacity prices under Table E-2.

III. PG&E's OWN EXTENSION OF THE FWM SO4's TABLE E-2 THROUGH 1988 REFUTES ITS ARGUMENTS IN ITS APPLICATION FOR REHEARING.

In its Application for Rehearing, PG&E repeatedly asserts that Table E-2 does not contain any firm capacity prices for facilities establishing FCAD's after 1987.*** PG&E then argues that under the terms of Table E-2, post-1987 firm capacity prices are not available under SO4.

In making these assertions, PG&E is not only mistaken, but is also rather disingenuous, since PG&E itself extended the Table E-2 in the FWM SO4 through 1988 using escalated prices based on the firm capacity price methodology previously adopted by the Commission.* PG&E extended the FWM SO4's Table E-2 at the request of FWM and Tosco. The extension was not controversial,

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**For example, since the FWM SO4 contains a March 1, 1987 SOD, if the Facility comes on line in 1988, the Decision would limit it to 1987 firm capacity prices, rather than the 1988 prices specified in the contract and explicitly set out in Table E-2. The Decision would thus wipe out the firm capacity prices fixed for 1988 by FWM and agreed to by PG&E at the time they entered the FWM SO4.

***See PG&E Application at 4-7, 9.

*The FWM SO4 is included as Appendix A to the FWM Application.

since it was made solely in the interest of completeness, to make explicit what both parties already understood to be part of the contract.

PG&E's own extension of this one Table E-2 completely undercuts its argument that Table E-2 by its plain terms was intended to end in 1987, and that the escalated firm capacity prices derived from Standard Offer No. 2 and applied to the SO4s were deliberately omitted for years beyond 1987. It is fatally inconsistent for PG&E to claim that the Commission cannot "imply" Table E-2 firm capacity prices beyond 1987, when PG&E itself made precisely this implication in its extension of the FWM SO4's Table E-2.

PG&E's past treatment of Table E-2 should make it clear that PG&E's current arguments before the Commission are simply an attempt to evade its obligations under its executed contracts. Even if ultimately defeated, these arguments are threatening the continued financability of alternative energy projects by undermining the contractual certainty that the Commission sought to achieve in adopting the standard contract format.** The Commission should not countenance such behavior by a party under its jurisdiction.

IV. CONCLUSION

All parties to these proceedings understand that under the terms of the SO4, firm capacity payments must be calculated on the basis of the Firm Capacity Availability Date. No party ever requested that the Commission change these terms and no party has defended the Commission's substitution of the SOD for the FCAD in calculating firm capacity prices under Table E-2. For the reasons set forth in FWM's Application for Rehearing, this retroactive amendment of SO4 must be corrected.

**See Decision 86-10-038* at 5 (explaining that the "crux" of Interim Standard Offer No. 4 is the price certainty provided to QFs).

Further, it is a fact that PG&E on its own has extended Table E-2, using the very escalated rates that it now decries. PG&E's actions fatally undercut its current efforts to deny that firm capacity payments beyond 1987 were clearly established under the SO4 contracts. PG&E current arguments, no matter how legally unsound, have called into question the contractual certainty intended by the Commission and essential to the continued efforts to obtain financing for qualifying facilities. Because final resolution of these issues is necessary before qualifying facility financings may proceed, FWM respectfully requests that the Commission expedite its consideration of these matters, and promptly deny PG&E's Application for Rehearing.

Respectfully submitted,

By: _____

Erica A. Ward
M. Curtis Whittaker
Skadden, Arps, Slate,
Meagher & Flom
919 18th Street, N.W.
Washington, D.C. 20006
(202) 463-8700

Attorneys for
FOSTER WHEELER POWER SYSTEMS, INC.

AMENDED IN SENATE JULY 8, 1983
AMENDED IN ASSEMBLY MAY 25, 1983
AMENDED IN ASSEMBLY MAY 16, 1983

CALIFORNIA LEGISLATURE—1983-84 REGULAR SESSION

ASSEMBLY BILL No. 1942

Introduced by Assemblymen Davis and Hauser

March 4, 1983

An act to add Chapter 3.2 (commencing with Section 4217.10) to Division 5 of Title 1 of the Government Code, and to amend Section 2821 of, *and to add Section 228.5 to,* the Public Utilities Code, relating to energy conservation.

LEGISLATIVE COUNSEL'S DIGEST

AB 1942, as amended, Davis. Energy conservation contracts: *private energy producers.*

(1) Existing law does not expressly authorize and prescribe procedures for public agencies to develop energy conservation, cogeneration, and alternate energy sources at the facilities of the public agencies.

This bill would expressly authorize and prescribe procedures for public agencies, as defined, to develop energy conservation, cogeneration, and alternate energy sources at the facilities of the public agencies. It would authorize, subject to specified conditions, a public agency to enter into an energy service contract and a facility ground lease, or a facility financing contract and a facility ground lease, or an energy sale contract. It would also define terms for the purpose of these provisions.

(2) Existing law requires the Public Utilities Commission to approve and establish equitable charges to be paid by an electrical corporation which purchases electricity from

any private energy producer employing other than a conventional power source for the generation of electricity.

This bill would ~~require that any contract~~ *additionally authorize the commission to specify the prices, terms, and conditions* for the purchase or sale of electricity ~~executed by~~ *between* an electrical corporation and a private energy producer ~~pursuant to the rules of the commission governing these contracts~~ *and these prices, terms, and conditions, so specified, would* be considered reasonable and prudent for all purposes.

(3) ~~Existing law defines the term "electrical corporation" for purposes of the Public Utilities Act.~~

~~This bill would specifically exclude from that definition a corporation or person employing cogeneration technology or producing power pursuant to prescribed provisions.~~

(3) The bill would define the terms "qualifying small power producer," "small power production facility," and "qualifying small power production facility," and "qualifying small power production facility" as having the same meaning as specified federal statutes and regulations and would provide that a qualifying small power producer owning or operating a small power production facility is not a public utility subject to the commission's jurisdiction solely because of this ownership or operation.

Vote: majority. Appropriation: no. Fiscal committee: ~~no~~ *yes.* State-mandated local program: no.

The people of the State of California do enact as follows:

SECTION 1. Chapter 3.2 (commencing with Section 4217.10) is added to Division 5 of Title 1 of the Government Code, to read:

CHAPTER 3.2. ENERGY CONSERVATION CONTRACTS

4217.10. To help implement the policy set forth in Section 25008 of the Public Resources Code, and to extend

that policy to facilities of local governments, public agencies may develop energy conservation, cogeneration, and alternate energy supply sources at the facilities of public agencies in accordance with this chapter.

4217.11. The following terms, whenever used in this chapter, have the meanings given in this section, except where the context clearly indicates otherwise:

(a) "Alternate energy equipment" means equipment for the production or conversion of energy from alternate sources, such as solar, biomass, wind, geothermal, hydroelectricity under 30 megawatts, remote natural gas of less than one billion cubic feet estimated reserves per mile from an existing gas gathering line, natural gas containing 850 or fewer British Thermal Units per standard cubic foot, or any other source of energy, the efficient use of which will reduce the use of fossil or nuclear fuels.

(b) "Cogeneration equipment" means equipment for cogeneration, as defined in Section 218.5 of the Public Utilities Code.

(c) "Conservation measures" means equipment, maintenance, load management techniques and equipment, or other measures to reduce energy use or make for a more efficient use of energy.

(d) "Conservation services" means the electrical, thermal, or other energy savings resulting from conservation measures, which shall be treated as a supply of such energy.

(e) "Energy conservation facility" means alternate energy equipment, cogeneration equipment, or conservation measures located in public buildings or on land owned by public agencies, the energy from which shall be consumed in whole or in part by the public agency.

(f) "Energy service contract" means a contract entered into by a public agency with any person, pursuant to which

the person will provide electrical or thermal energy or conservation services to a public agency from an energy conservation facility.

(g) "Facility financing contract" means a contract entered into by a public agency with any person whereby the person provides financing for an energy conservation facility in exchange for repayment of the financing and all costs and expenses related thereto by the public agency. A facility financing contract may provide for the person with whom the public agency contracts to provide any combination of feasibility studies for, and design and construction of, all or part of the energy conservation facility in addition to the financing and other related services, and may provide for an installment sale purchase, *another form of purchase*, or amortized lease of the energy conservation facility by the public agency.

(h) "Facility ground lease" means a lease of *all, or any portion of,* land or a public building owned by, or under lease to, a public agency to a person in conjunction with an energy service contract or a facility financing contract. A facility ground lease may include, in addition to the land on which energy conservation facilities will be located, easements, rights of way, licenses, and rights of access, for the construction, use, or ownership by the person of the facility and all related utility lines, and off-site improvements related thereto.

(i) "Person" means, but is not limited to, any individual, company, corporation, partnership, public agency, state agency, association, proprietorship, trust, joint venture, or other entity or group of entities.

(j) "Public agency" means a county, city and county, city, district, community college district, school district, joint powers authority or other entity designated or created by a political subdivision relating to energy development projects, and any other political subdivision or public corporation in the state, except the State of Cali-

fornia, the California State University, and the University of California.

(k) "Public building" includes any structure, building, facility, or work which a public agency is authorized to construct or use, and automobile parking lots, landscaping, and other facilities, including furnishings and equipment, incidental to the use of any structure, building, facility, or work, and also includes the site thereof, and any easements, rights-of-way appurtenant thereto, or necessary for its full use.

4217.12. Notwithstanding any other provision of law, a public agency may enter into an energy service contract and a facility ground lease on such terms as its governing body determines are in the best interests of the public agency if the determination is made at a regularly scheduled public hearing, public notice of which is given at least two weeks in advance, and if the governing body finds:

(a) That the anticipated cost to the public agency for thermal or electrical energy or conservation services provided by the energy conservation facility under the contract will be less than the anticipated marginal cost to the public agency of thermal, electrical, or other energy that would have been consumed by the public agency in the absence of those purchases.

(b) That the difference, if any, between the fair rental value for the real property subject to the facility ground lease and the agreed rent, is anticipated to be offset by below-market energy purchases or other benefits provided under the energy service contract.

4217.13. Notwithstanding any other provisions of law, a public agency may enter into a facility financing contract and a facility ground lease on such terms as its governing body determines are in the best interest of the public agency if the determination is made at a regularly scheduled public hearing, public notice of which is given at least

two weeks in advance, and if the governing body finds that funds for there payment of the financing or the cost of design, construction, and operation of the energy conservation facility, or both, as required by the contract, are projected to be available from revenues resulting from sales of electricity or thermal energy from the facility or from funding which otherwise would have been used for purchase of electrical, thermal, or other energy required by the public agency in the absence of the energy conservation facility, or both.

4217.14. Notwithstanding any other provision of law, the public agency may enter into contracts for the sale of energy produced by the energy conservation facility at such rates and on such terms as are approved by its governing body. Any such contract may provide for a commitment of firm electrical capacity.

4217.15. The public agency may, but is not required to, base the findings required under Sections 4217.12 and 4217.13 on projections for electrical and thermal energy rates from the following sources:

(a) The public utility which provides thermal or electrical energy to the public agency.

(b) The Public Utilities Commission.

(c) The State Energy Resources Conservation and Development Commission.

(d) The projections used by the Department of General Services for evaluating the feasibility of energy conservation facilities at state facilities located within the same public utility service area as the public agency.

4217.16. Prior to awarding or entering into an agreement or lease, the public agency may request proposals from qualified persons. After evaluating the proposals, the public agency may award the contract on the basis of the experience of the contractor, the type of technology em-

ployed by the contractor, the cost to the local agency, and any other relevant considerations.

4117.17. The provisions of this chapter shall not be deemed to limit the authority of any public agency to construct energy conservation projects or to enter into other leases or contracts relating to the financing construction, operation, or use of alternate energy type facilities in any manner authorized under existing law.

4217.18. The provisions of this chapter shall be construed to provide the greatest possible flexibility to public agencies in structuring agreements entered into hereunder so that economic benefits may be maximized and financing and other costs associated with the design and construction of alternate energy projects may be minimized. To this end, public agencies and the entities with whom they contract under this chapter should have great latitude in characterizing components of energy conservation facilities as personal or real property and in granting security interests in leasehold interests and components of the alternate energy facilities to project lenders.

~~The term "clerical corporation" as defined in Section 218 of the Public Utilities Code shall not include any corporation or person employing cogeneration technology or producing power pursuant to Section 4217.12, 4217.13, or 4217.14.~~

SEC. 2. Section 228.5 is added to the Public Utilities Code, to read:

228.5. (a) The terms "qualifying small power producer," "small power production facility," and "qualifying small power production facility" have the same meaning as found in Section 796 of Title 16 of the United States Code and regulations enacted pursuant thereto.

(b) Notwithstanding any other provision of law, a qualifying small power producer owning or operating a small power production facility is not a public utility subject to the general jurisdiction of the commission solely because of the ownership or operation of the facility.

SEC. 3. Section 2821 of the Public Utilities Code is amended to read:

2821. The commission shall approve and establish equitable charges to be paid by an electrical corporation which purchases electricity from any private energy producer employing other than a conventional power source for the generation of electricity. ~~The commission may act in this regard on its own motion or on application of an electrical corporation or a private energy producer.~~

~~Any contract for the purchase or sale of electricity executed by an electrical corporation and a private energy producer pursuant to the rules of the commission governing these contracts shall be considered reasonable and prudent for all purposes.~~

The commission may also specify the prices, terms, and conditions for the purchase or sale of electricity between an electrical corporation and a private energy producer, and these prices, terms, and conditions, so specified, shall be considered reasonable and prudent for all purposes. The commission may act to specify these prices, terms, and conditions on its own motion or on application of an electrical corporation or a private energy producer.

SENATE COMMITTEE ON ENERGY AND PUBLIC UTILITIES

AB 1942 - Davis
As Amended 7-8-83
Government Code

Hearing Date: 7-12-83

Finance: Yes

Public Utilities Code

BACKGROUND

LOCAL AGENCIES

During recent years, as energy costs have risen and sources of income have been reduced, many public agencies have initiated energy conservation and development programs. Typical projects include the City of Santa Clara's co-generation project developed in conjunction with a local pulp and paper mill, the City of Modesto using purified gas from sewage sludge to power city vehicles, and the City of Fairfield's wind generation project.

There are two constraints which inhibit public agency development of alternative energy projects. One is a lack of funding and the other is a lack of specific authorization to develop alternative energy projects. Opportunities to work with private developers have been limited by uncertainty about legal authority to contract to develop projects on public property.

PRIVATE ENERGY PRODUCERS

Following the enactment of the federal Public Utility Regulatory Policies Act (PURPA) in 1978, the PUC in 1980 issued Order Instituting Rulemaking-2 (OIR-2). This investigation was begun for the purpose of establishing standards governing the prices, terms, and conditions of electric utility purchases from qualified private energy producers.

In January, 1982, the PUC issued a decision in OIR-2. The decision, among other things, ordered the major California electric utilities to file standard offers for power purchases based upon avoided cost principles. The offers are to be made available to all energy facilities that qualify under PURPA.

Besides the standard offer, contracts may be negotiated between the utility and an individual energy producer, taking into account specialized costs of that producer. Most contracts are of the negotiated type. Both negotiated contracts and standard offer contracts between a utility and a private energy producer are subject to PUC review for reasonableness at the time the utility seeks to include the contract costs in their rate base.

AB 1942, as amended 7-8-83, addresses two issues:

(1) The bill would authorize and prescribe procedures for public agencies, to enter into contracts with private investors to develop energy conservation, cogeneration, and alternate energy sources at public facilities.

The bill exempts public agencies and private investors producing energy pursuant to the provisions of the federal Public Utilities Regulatory Policies Act from being considered "public utilities" or "electrical corporations" and therefore being subject to PUC review.

(2) AB 1942 also provides that the PUC may, on its own motion or that of a utility or private energy producer, act to specify prices and terms for any purchase or sale contract entered into by a utility and a private energy producer. These contracts shall be deemed "reasonable and prudent" for all purposes.

COMMENTS

1. Supporters note that energy conservation and development projects at public facilities have provided signifi-

cant new energy sources and revenue to the government agencies involved.

2. PG&E, although in support of the bill, has suggested some technical amendments. They feel it would be helpful to clarify the definitions of the following five terms: a) alternate energy equipment; b) energy conservation facility; c) facility ground lease; d) energy; e) electricity.

3. AB 1659 (Farr), also before this committee, deals with local agency energy development through the formation of Community Energy Authorities.

POSITIONS

Support:

County Supervisors Association of California
League of California Cities
Pacific Gas and Electric Company

Neutral:

Public Utilities Commission

LB, AB 1942, Analysis
Hearing Date: 7-12-83